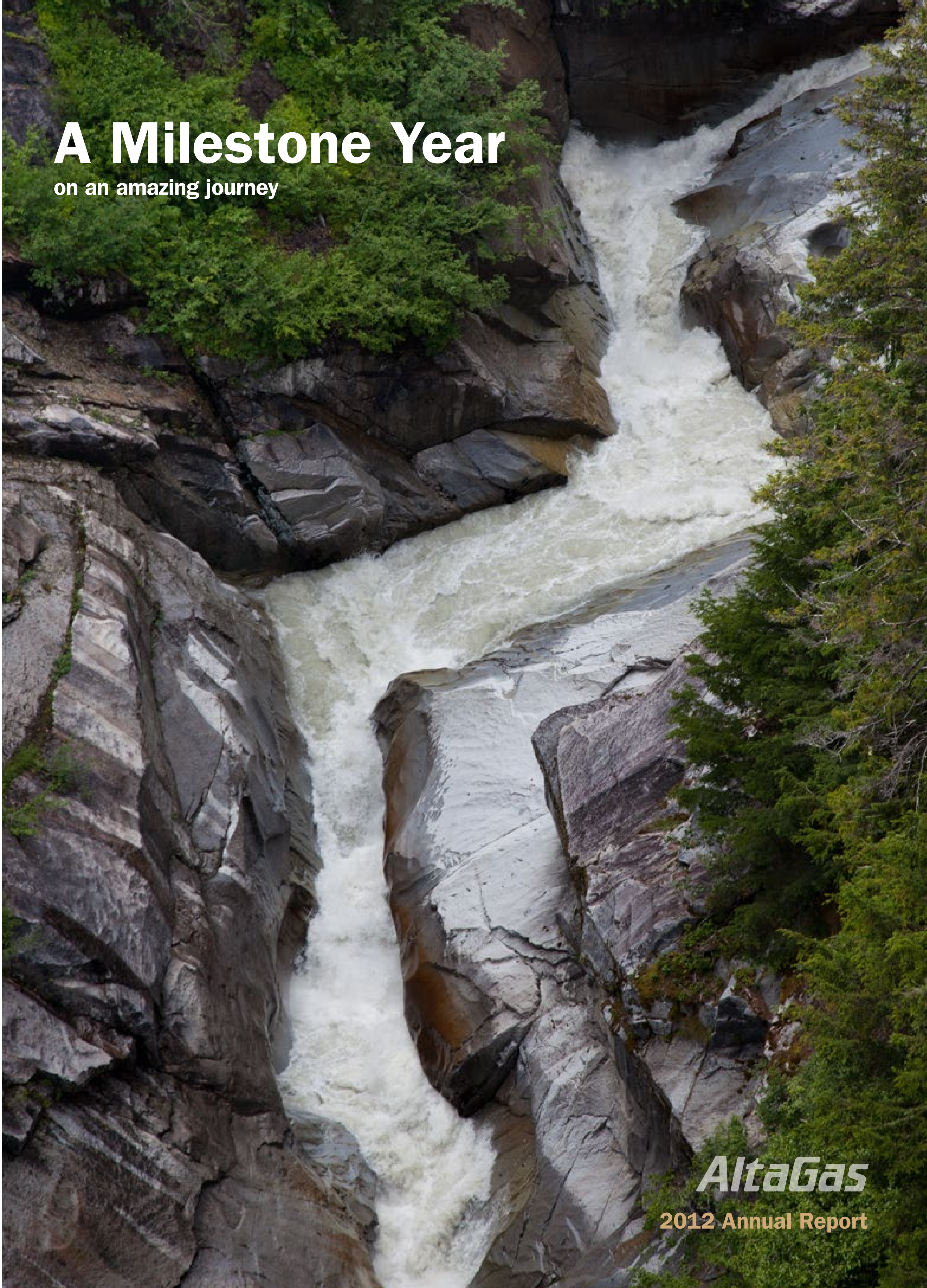


A Milestone Year

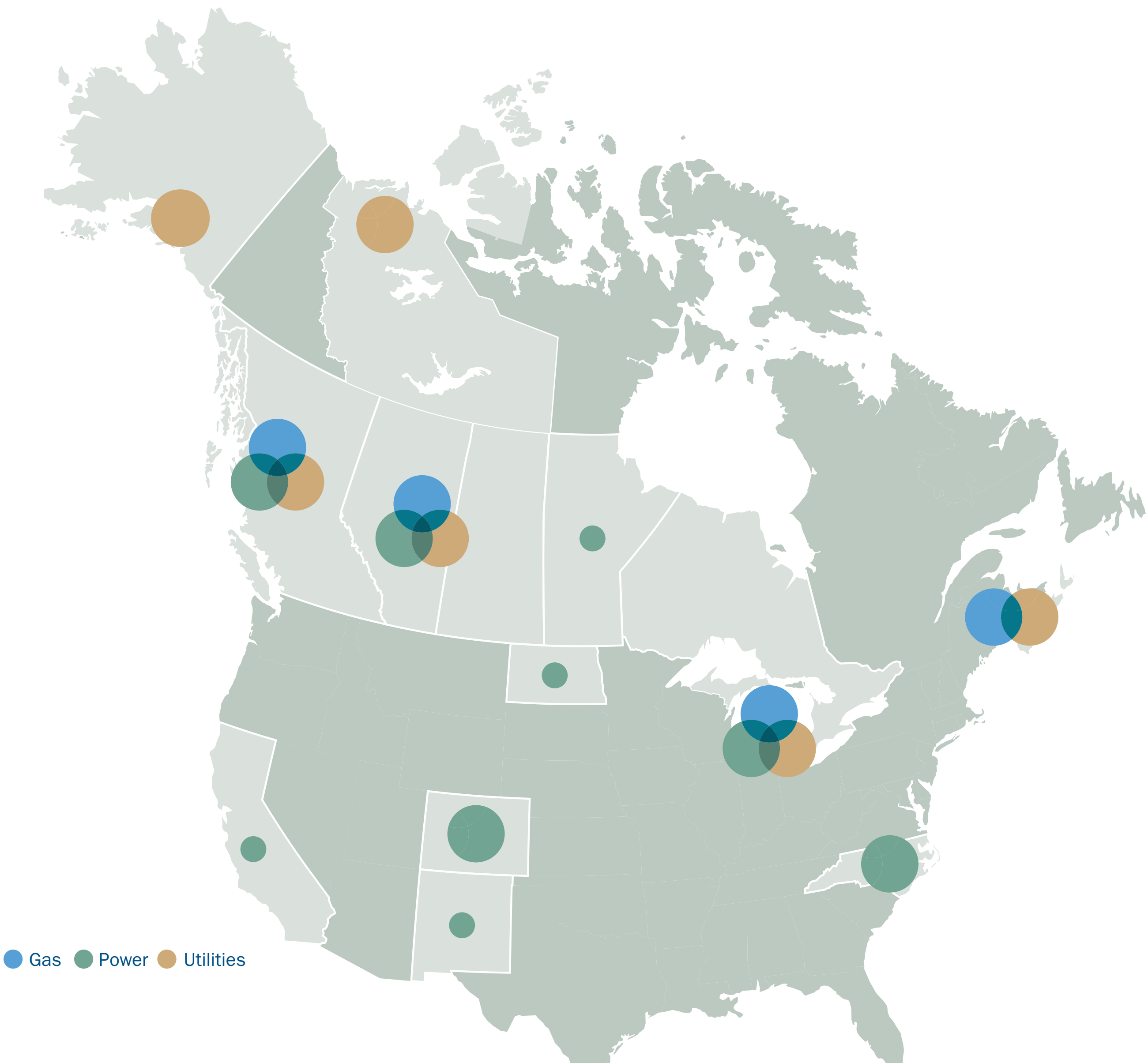
on an amazing journey

AltaGas

2012 Annual Report

AltaGas is a leading North American energy infrastructure company.

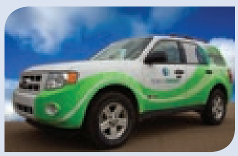
In 2009, we embarked on a five-year journey to double our cash flow and deliver cleaner energy to communities, superior returns to shareholders and enhanced value to our customers, communities and employees. We made great strides in 2012 and are well on our way to achieving these goals.



Our strategically located assets create a strong competitive advantage.

We are a major player in natural gas – a fuel that is affordable, clean and abundant. We deliver natural gas to nearly 550,000 utility customers and touch over 2 Bcf/d. We are making great progress in renewable energy with wind, biomass and run-of-river hydro projects and we are strategically positioned in British Columbia for export of liquefied natural gas (LNG) and liquefied petroleum gas (LPG) to global markets. As we integrate our assets into strategic geographic clusters, we grow stronger and more dynamic. Our diverse assets, underpinned by long-term contracted and stable cash flows, support our financial strength and stability. We continue to grow profitably, adding sustainable cash flows that support dividend growth and capital appreciation for our investors.

Major Milestones in 2012

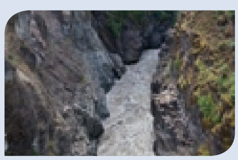


SEMCO

Completed a $1.14 billion acquisition, the largest in our 18-year history

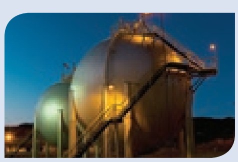
Gordondale

Constructed a 120 Mmcf/d deep-cut gas processing plant in the Montney area



Forrest Kerr

Completed 75 percent of our 195 MW run-of-river hydro project



Harmattan

Constructed the 250 Mmcf/d Co-stream project

Busch Ranch

Began commercial operations at a 29 MW wind farm in Colorado

Contents

Tracking Our Progress

In 2012, we met our milestones adding more customers, more natural gas processing capability, more earnings and more new projects for future growth.

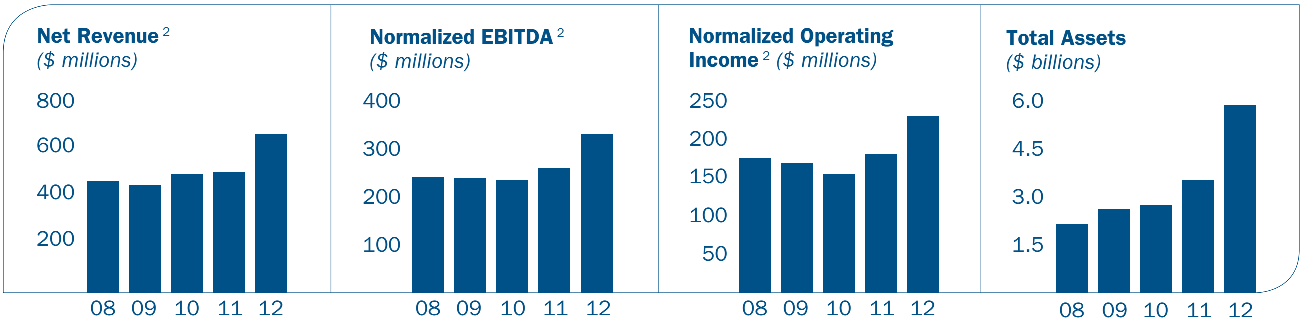
David Cornhill
Chairman and Chief Executive Officer

A Milestone Year

The AltaGas team made significant strides on our journey as a leading North American energy infrastructure company. In 2012, we completed our largest corporate acquisition, taking our first major step into the U.S. utilities market. We constructed the two largest natural gas processing projects in our history, and we made considerable progress on our three Northwest run-of-river hydro projects, which are expected to be in service beginning in 2014.

The new assets added in 2012 are expected to contribute to earnings and cash flow growth. Our achievements reflect the consistent execution of our strategy, and we now look to enhance productivity and further streamline our businesses.

Highlights[1]



1 Restated to comply with US GAAP from 2010 onwards.
2 Non-GAAP financial measure; see discussion in "Non-GAAP Financial Measures" section of the annual MD&A.

Long-Term Growth

In 2012, we delivered record financial results and expect this growth to continue. We have positioned AltaGas to deliver growth in earnings and cash flow per share for several years to come, and we are working to set the stage for long-term growth.

Excellent Access to Capital

Our growth is supported by strong access to the debt and equity markets. We completed our largest equity issuance with $400 million to finance SEMCO. This acquisition was accretive by 10 percent on a per share basis. We also had strong support in the debt and preferred share markets and issued $550 million in Medium Term Notes (MTN). This included our longest tenure, largest issuance and lowest coupon MTN in September 2012. We also completed our first U.S. dollar denominated preferred share issuance of $200 million.

Natural Gas Renaissance Creates Opportunities

The renaissance of natural gas in recent years has provided AltaGas with many opportunities to create social and economic value. Most significantly, we are embarking on a new joint venture with a Japanese partner, Idemitsu Kosan Co. Ltd., to export energy from Canada to Asian markets. We have a significant competitive advantage – one we are very excited to leverage. With the only natural gas pipeline from eastern B.C. to Canada's west coast, AltaGas is best positioned to deliver natural gas for export from Canada ahead of any other project.

	Growth Projects	Milestones in 2012	Status
Power	**Forrest Kerr**	• Continue power tunnel excavation – 85 percent complete • Continue headwork/intake construction – 75 percent complete • Complete powerhouse excavation – Q2 2012	✓
Power	**McLymont Creek and Volcano Creek**	• Receive environmental approvals • Start McLymont Creek road/bridge construction	✓
Power	**Harmattan and Gordondale power plants**	• Complete on time and on budget	✓
Gas	**Blair Creek expansion**	• In service Q2	**In service Q3**
Gas	**Harmattan Co-stream**	• In service Q2	**In service Q4**
Gas	**Gordondale Gas Plant**	• In service Q4	✓
Utilities	**Rate base growth**	• Increase rate base 10 percent in Canada	**Achieved 8 percent**
Utilities	**SEMCO acquisition**	• Close in Q3	✓

20% increase in gas processing capability

13% increase in power generating capacity

↑ more than doubled our utility rate base

Largest Acquisition and Rate Base Expansion

Our Utilities business achieved a significant milestone in 2012. We negotiated, closed and integrated the $1.14 billion acquisition of SEMCO, the largest in our 18-year history. Adding to our track record of operating natural gas utilities across Canada, SEMCO extends that success into the attractive U.S. market. We now safely and reliably serve nearly 550,000 customers in North America, with a rate base of over $1.3 billion.

In Canada, we increased our rate base by 8 percent. In Nova Scotia, we expanded the Heritage Gas utility and began constructing compressed natural gas stations for markets not easily served by pipelines. In Alberta, we continued system betterment, and in British Columbia we began delivering compressed natural gas (CNG).

New and Expanded Gas Assets Boost Processing Capability

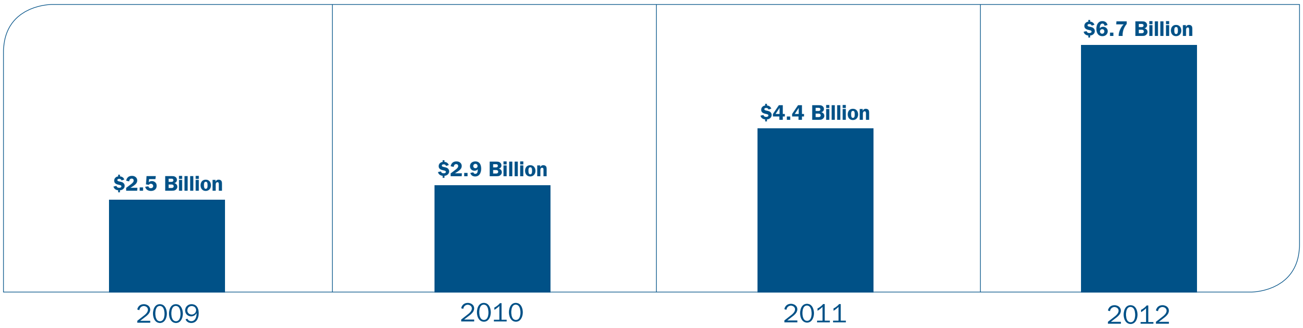
Our Gas business accomplished more in 2012 than in any other year. In building two of our largest gas projects, we overcame many construction challenges and learned much that will benefit future projects. Despite cost overruns at both projects, driven by a tight labour market and material and equipment delays, we completed Gordondale three days ahead of schedule and the Co-stream project in the fourth quarter.

We added over 420 Mmcf/d of processing capability, expected to be at least 75 percent utilized by the end of 2013. In total, in 2012 we added over $500 million in new and expanded assets, specifically the Gordondale gas processing plant, the Harmattan Co-stream project, the Blair Creek facility expansion and a significant interest in the Gilby Gas Plant.

SEMCO: Quadrupled our customer base

Gordondale: Completed ahead of schedule

Total Enterprise Value



Significant Progress Growing our Renewable Portfolio

Our three Northwest run-of-river projects in B.C. create exciting step-change growth. Together, we expect them to deliver clean energy to approximately 95,000 households and generate $130 million in EBITDA. These projects are underpinned by 60-year EPAs with BC Hydro, fully indexed to CPI.

In one year, we advanced the 195 MW Forrest Kerr project from 10 percent completion to over 75 percent – a significant accomplishment. We completed the intake structure, the powerhouse and 90 percent of the tunneling. Today we are ahead of schedule and on budget for service starting in mid-2014. We also made significant progress on our McLymont Creek and Volcano Creek projects, which total 82 MW. We received all material licenses and permits and construction is well underway for service in 2015.

In 2012, we increased our U.S. renewable power generation to approximately 50 MW, by acquiring our first wind farm and biomass generation assets. As an emerging leader in renewable energy, these assets strengthen our power generation portfolio and position us for further growth in the U.S. power market. They are fully contracted with long-term power purchase agreements that support our goal of stable earnings.

The 15 MW gas-fired Cogeneration II facility at the Harmattan complex and the 3 MW gas-fired peaking facility at Gordondale were also commissioned on time and on budget. These are great examples of how we maximize asset profitability by capitalizing on the physical and economic links along the energy value chain.

Forrest Kerr: On budget and ahead of schedule

Busch Ranch: Our first wind farm in the U.S.

Our Next Steps

We have a clear line of sight on our path forward. We are reviewing $2 billion in new opportunities that will shape our next phase of growth beyond 2014.

New Joint Venture

On January 28, 2013, we announced a strategic partnership with Idemitsu. Together we are pursuing several opportunities to export energy from Canada to Asian markets. We have the only natural gas pipeline from eastern British Columbia to Canada's west coast, positioning us to begin exporting LNG, LPG and CNG well ahead of other projects.

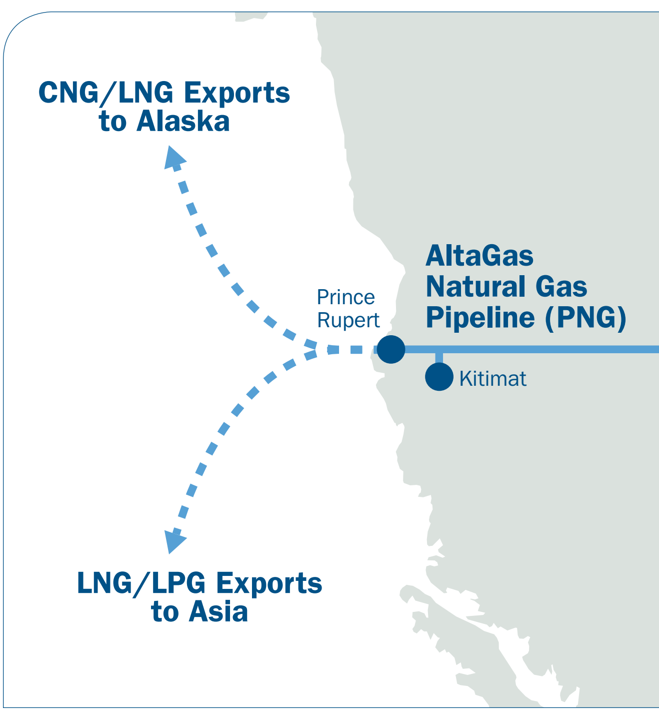
With our partner, we expect to secure sales contracts, and with our knowledge and expertise in Canada, we can secure supply. 2013 will be a big year as we complete feasibility studies for the expansion of our Pacific Northern Gas Ltd. (PNG) system and embark on the next leg of our journey to grow beyond 2014.

Helping Alaska Secure Natural Gas Supply

As the owner of the largest natural gas distribution utility in Alaska, we are committed to ensuring the security and reliability of natural gas for our customers. We are well positioned to partner with the government, other utilities and the regulators to find the best solution for Alaskans to ensure they have energy security.

One possibility is to deliver CNG and LNG from our PNG system. An expansion of the PNG system would create incremental capacity to deliver natural gas to the west coast for shipping to Alaska. This option would bring significant benefits to customers in Alaska and British Columbia while meeting our prime objective as a utility – to provide reliable and secure natural gas supply in the most cost efficient manner.

Opening Up New Markets

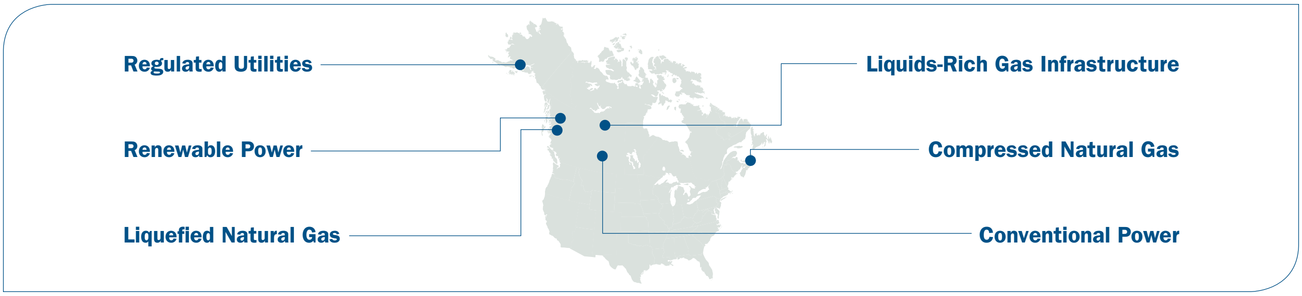


AltaGas' joint venture with Idemitsu opens up new markets for Canadian LNG and other products. It will link producers in Western Canada to global customers.

AltaGas | Idemitsu Kosan

Idemitsu Kosan Co., Ltd. is a Japanese petroleum company. It owns and operates oil platforms and refineries, and produces and sells petroleum, oils and petrochemical products.

Opportunities Coast-to-Coast



CNG to Serve Growing Natural Gas Demand

CNG is a cost effective way to meet the growing demand for natural gas, especially in areas where building natural gas pipelines may not be economical. Since late 2012, PNG has been delivering compressed natural gas by truck to a revitalized coal mining facility in British Columbia.

In 2012, AltaGas began developing the infrastructure to increase natural gas supply in Nova Scotia. In 2013, we plan to begin distributing CNG to customers by truck. With the resurgence of natural gas as an affordable, cleaner burning fuel, we expect to continue growing this new business line. In 2012, North American natural gas was 83 percent less expensive than oil on an energy equivalent basis, and this gas discount is expected to continue.

Meeting Increased Demand for Clean Power

Globally, there is a growing need for sustainable energy sources. Because natural gas is abundant in supply and cleaner than other fossil fuels, we believe demand for gas-fired and renewable generation will drive future growth in power generation. We have the expertise to build, own and operate both types of power generation and expect to grow our natural gas-fired and renewable portfolio to meet this demand.

Serving Producers in Liquids-Rich Areas

As producers focus on liquids-rich areas and deliver a growing supply of natural gas and natural gas liquids, the need for new markets and the infrastructure to get these products to market also grows. We are well positioned to build on our current geographic and business footprint to meet the needs of producers and new markets.

Letter to Shareholders

> *I am very proud of the company we have built. From seed capital of $37,000 in 1994 to an enterprise value of $7 billion today, we have been on an amazing journey of creating both economic and social value along the way. The next phase of our journey is even more exciting.*

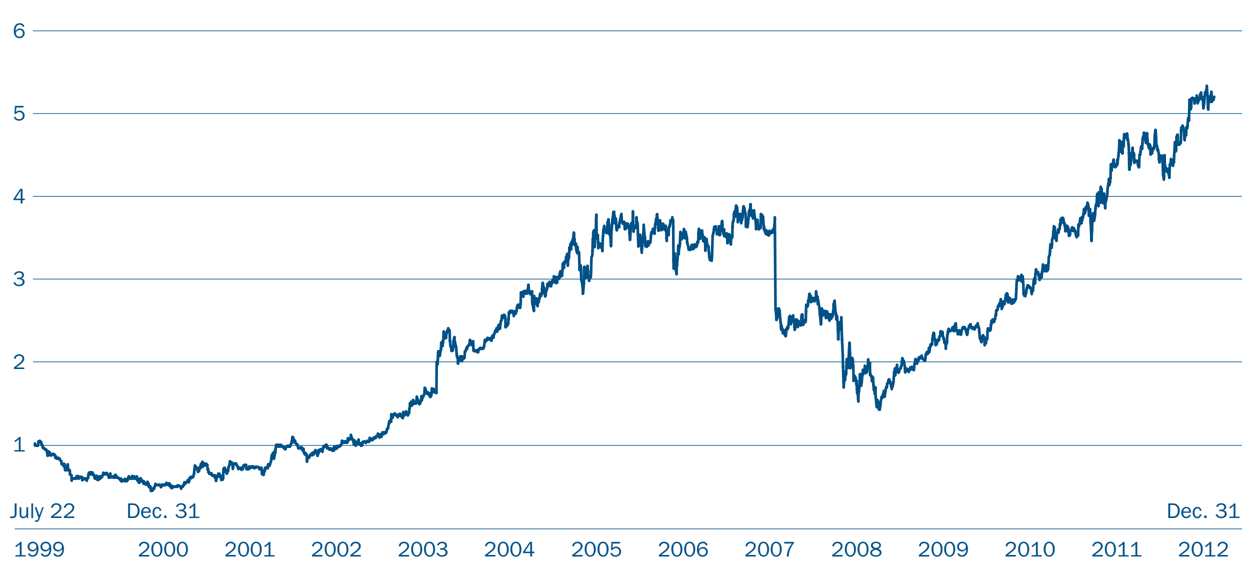
Creating Value for Shareholders
One of our many strengths is our consistent focus and ability to execute our strategy. We know where we are going, we know how to get there and we do what we say we are going to do.

This discipline and commitment to building a portfolio of long-life, stable assets has resulted in solid returns for investors, both in dividend growth and capital appreciation. In 2012, we increased our dividend by 4.3 percent. Our payout ratio was approximately 50 percent and at the current level, we expect our payout ratio to be less in 2013. As we continue to increase cash flow from long-term, stable assets, we have ample room to grow dividends. In 2012, our share price also increased 5.4 percent, and during the last 10 years, it has grown over 450 percent.

Adding Value for Communities, Customers and Employees
Executing our strategy allows us to create more than just shareholder value. We pride ourselves in making business decisions that create value for our shareholders, local communities, customers and our employees.

Social value is about understanding our place in the bigger picture and creating benefit beyond the bottom line. We take pride in pursuing clean forms of energy and renewable power and in reducing our overall emissions. AltaGas has reduced direct greenhouse gas emissions by 1.4 million tonnes (CO_2e) since 2007, and this will only improve as we expand our renewable power portfolio.

Lifetime Total Shareholder Return *($ thousands)* [1]



1 Based on purchasing 100 shares at $10.22 per share.

We take pride in giving back to the communities where we live and work, with numerous contributions of both volunteer hours from employees and donations to hundreds of local organizations. From corporate sponsorships of Cross Country Canada, STARS and The United Way, to donations supporting local theatre companies and kids cancer programs, our reach reflects our values.

We also pride ourselves in developing strong relationships with community members and First Nations, mindful that these relationships influence our success. In 2012, between 20 and 30 percent of the workforce at our Northwest Projects was comprised of Tahltan Nation members.

Our employees take great care to ensure safe operations, whether constructing our projects or delivering reliable services to our customers. We completed construction of the Gordondale processing facility with no lost-time injuries during 16 months of construction. In 2012, we conducted an integrity risk assessment of our transmission pipelines and modified our pipeline maintenance and monitoring schedule based on these findings. We also monitor vehicle accidents company wide. In 2012, we recorded one vehicle accident for every 261,705 kilometres travelled. Safety is a never-ending road of continuous improvement, and we are steadfastly committed to this journey.

One Vision, Many Hands

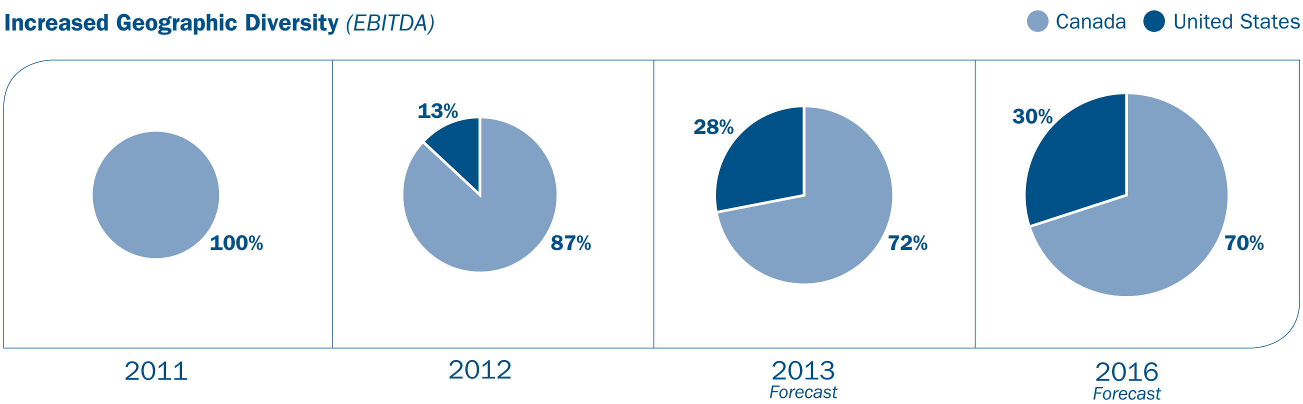
Our success is not achieved by one person, project or business segment. It takes a team all inspired by the same vision – to be a leading North American energy infrastructure company. I would like to thank our employees, the board, investors, customers, business partners and our service providers for helping us deliver a milestone year. Your belief in our vision and commitment to our success is what drives this company forward. And there's much more to come.

David W. Cornhill
Chairman and Chief Executive Officer

On Solid Ground

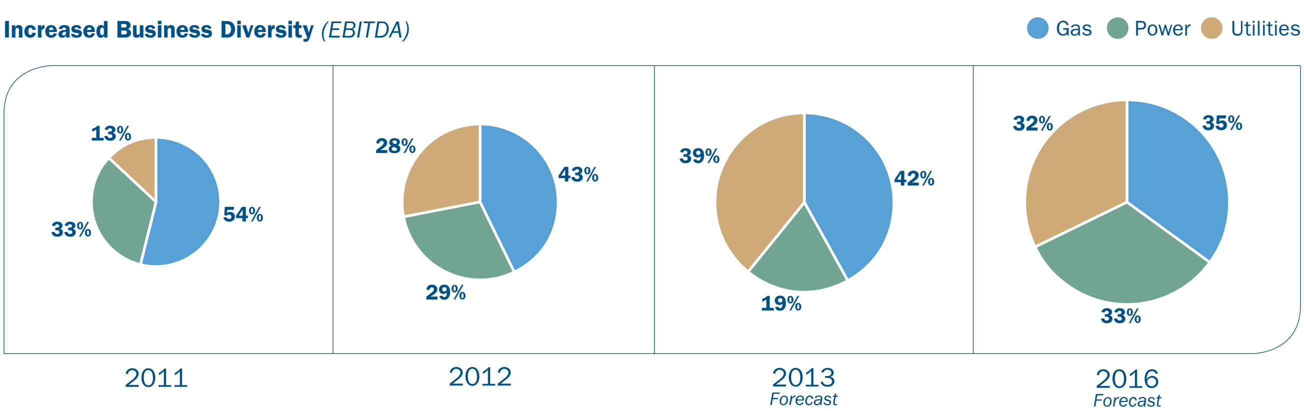
AltaGas has continuously positioned itself to capitalize on changing market dynamics. The steps we have taken have resulted in a portfolio of long-life assets that are stable and diverse. This diversity allows us to continue adapting and creating value for the long term.

Increased Geographic Diversity *(EBITDA)*



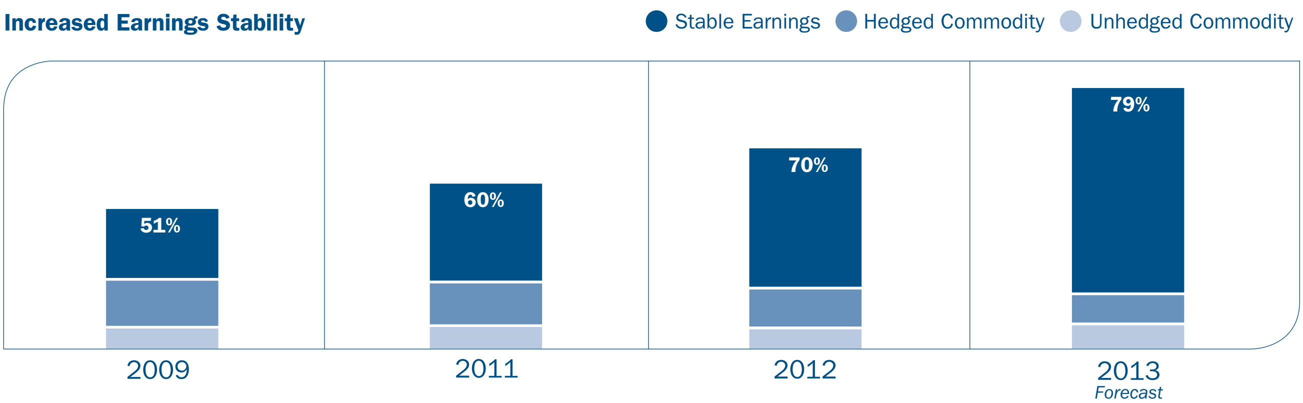
In 2012, we made the largest acquisition in our history, giving us a significant U.S. presence. By adding utilities in Michigan and Alaska, and renewable power generation assets in Colorado, Michigan and North Carolina, we expect 28 percent of EBITDA to come from the U.S. in 2013. We believe the U.S. is a good place to do business. With renewed demand for natural gas, we see many opportunities to continue our U.S. growth.

Increased Business Diversity *(EBITDA)*



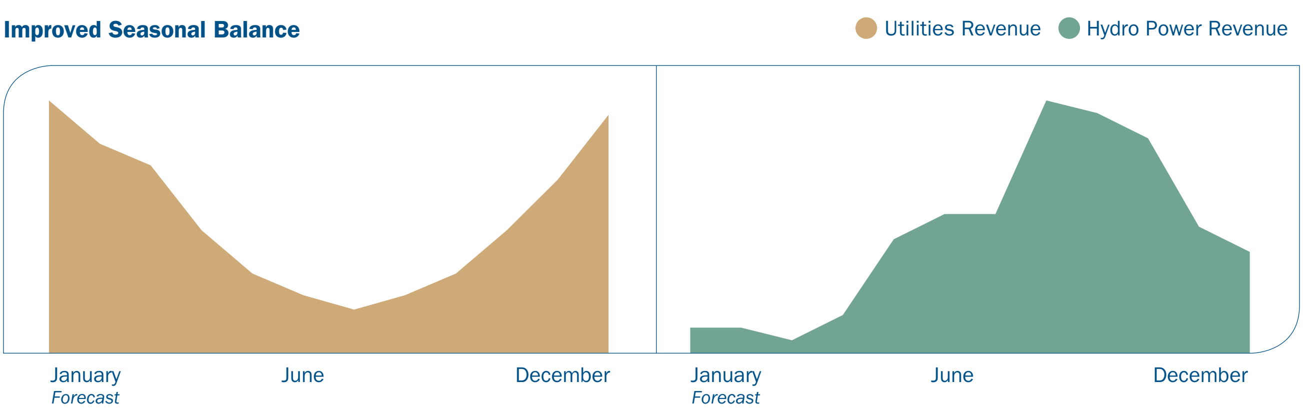
In 2011, our gas assets made up 54 percent of our operating EBITDA, while power and utilities represented 33 and 13 percent, respectively. With the addition of SEMCO in 2012, we expect to be more heavily weighted in utilities in 2013. When Forrest Kerr is commissioned in 2014, we expect the three business lines to be more equally balanced. While this is our long-term goal, the weighting could shift over time as we continue to capitalize on growth opportunities.

Increased Earnings Stability



Before 2011, much of our income came from the sale of power and natural gas liquids, which were exposed to commodity prices. In 2009, we embarked on a strategy to reduce this exposure and add assets underpinned by regulated returns or long-term contracts. The Gordondale gas plant, Harmattan Co-stream project and our renewable power generation assets are all underpinned by long-term contracts with strong counterparties. The SEMCO acquisition added $0.8 billion in regulated natural gas utility assets.

Improved Seasonal Balance



In 2013, we expect significant seasonality in our results as SEMCO contributes its first full year of earnings. Utilities earn most of their income in the first and fourth quarters in the heating seasons. Starting in 2014, we expect that seasonality to be offset with cash flows from Forrest Kerr, as run-of-river projects earn most of their income in the second and third quarters from winter run-off. Together these assets reduce the seasonality of our businesses, providing investors with stable and predictable cash flow year-round.

Gas

Liquids-rich. Long-term. Contracted.

On our journey, we are transforming our Gas business to focus on liquids-rich gas and larger deep-cut facilities to increase netbacks for producers.

A Year of New Assets and Added Capacity

2012 was a remarkable year for our gas business, which delivers gas processing, transmission, NGL extraction and energy management services to customers. We added over $500 million and 420 Mmcf/d of processing capability in new and expanded assets. We constructed the largest sour gas processing facility built in Alberta in the last 15 years – in record time and ahead of schedule. This plant serves the liquids-rich Montney area and is expected to continue attracting producers seeking to maximize their netbacks.

Expansion at our Harmattan complex added over 25,000 Bbls/d of incremental ethane supply, which otherwise would not have been extracted in Alberta. The expansion used the 250 Mmcf/d of spare capacity at the facility, making it a very cost effective solution. The Blair Creek expansion, also in the Montney area, added 50 Mmcf/d of processing capacity.

We also purchased a sizeable interest in the Gilby Gas Plant. We continue to work with regional producers and current customers to connect this and other plants to our JEEP facility. This would bring deep-cut capability to our customers and increase ethane production to support the Alberta petrochemical industry.

All the assets added in 2012 are underpinned by long-term contracts which enhance our earnings stability. They also set the stage for significant future earnings growth and demonstrate our ability to add value.

Two-thirds	20%	20-year
of our processing capacity serves liquids-rich areas	increase in gas throughput capability	cost-of-service agreement underpins the Co-stream project at Harmattan

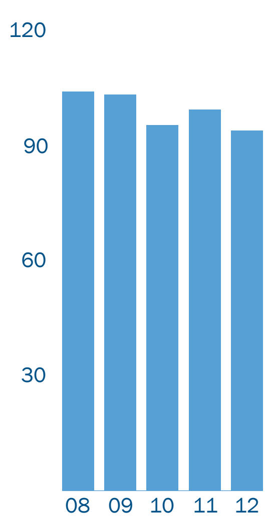
As we grow our gas processing capacity, we enter into long-term contracts to ensure stable returns. Our focus on operational efficiencies and productivity enhances customer and shareholder value.

Strategy and Next Steps

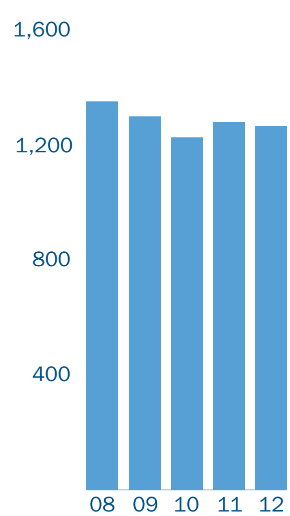
The race to the west coast to find new markets for Canadian natural gas is expected to result in increased demand for gas processing infrastructure as new reserves are exploited. AltaGas is a leader in gas processing with proven ability to build infrastructure to meet customers' needs. We plan to grow by expanding current plants and adding new larger plants with deep-cut capability in areas with strong drilling activity.

As dry gas areas continue to see low producer activity, we are focused on operational efficiencies by lowering costs and increasing productivity. This will allow us to capitalize on increased processing opportunities when natural gas prices rebound or new markets are secured.

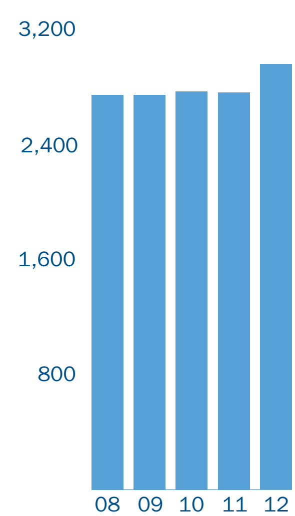
Normalized Operating Income *($ millions)*



Gas Throughput *(Mmcf/d)*



Processing Capacity *(Mmcf/d)*



Power

Diverse. Dynamic. Renewable.

With a growing mix of hydroelectric, wind, biomass and gas-fired generation, our power business is poised to generate significant stable cash flow, while reducing our carbon footprint.

Strategy

Our power business is focused on building a strong, diversified portfolio of assets that establishes us as a leader in renewable energy and positions us for future growth in Canada and the U.S.

A Year of Significant Progress

Our biggest accomplishment in 2012 was the considerable progress made on our Forrest Kerr run-of-river project. This $725 million project is ahead of schedule and on budget. We excavated the power house, completed the tailrace, access and construction tunnels, and completed a significant portion of the power tunnel. We also began constructing the 37-km transmission line which will deliver power from Forrest Kerr. Most importantly, we completed construction of the intake structure, allowing us to divert the river so we could begin in-river work one year ahead of schedule. We also made significant progress on the McLymont Creek and Volcano Creek projects. We received all material permits and licenses, completed the road to the Iskut River and began constructing the bridge across the Iskut.

In the U.S., we began operating our first renewable assets, including interests in biomass plants in Michigan and North Carolina and a wind farm in Colorado. We see many opportunities to build on this 50 MW power portfolio in the U.S. market.

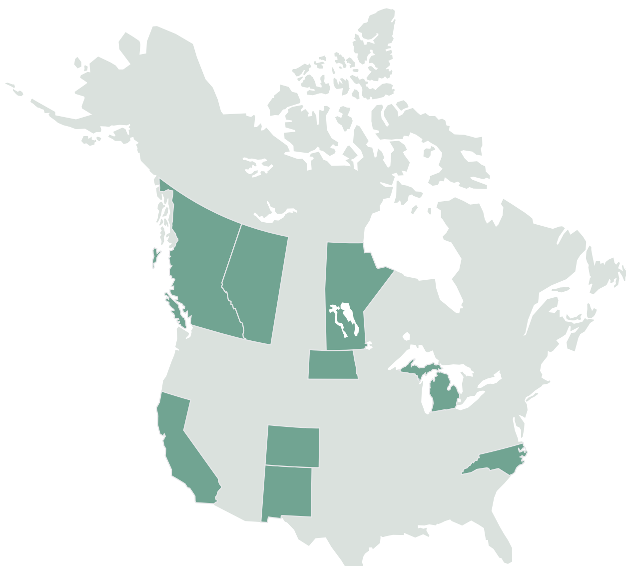
In Alberta, we continued to diversify away from the coal-fired Sundance Power Purchase Agreement (PPA) by constructing new gas-fired assets. The second base-load cogeneration facility at Harmattan and the gas-fired peaker built at the new Gordondale gas plant are excellent examples of AltaGas' strategy to maximize value along the energy value chain.

13%
increase in power generating capacity

50 MW
of renewable power assets added in the U.S.

60-year
fully inflation-indexed EPAs with BC Hydro

The significant progress made on our Northwest Projects gives us confidence that we can deliver on our strategy to meet the growing demand for clean power in North America.

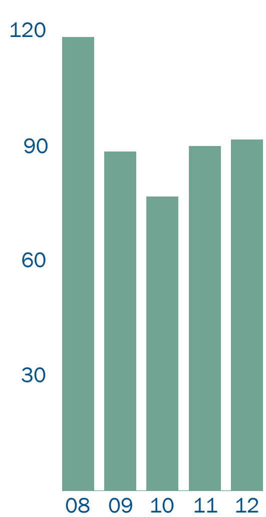


Preparing for Step-Change Growth

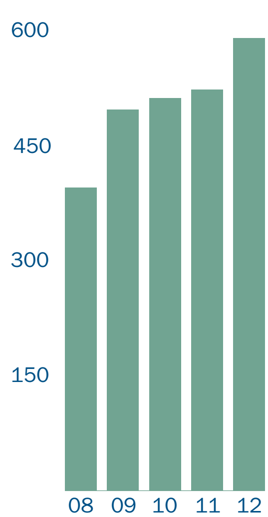
In 2013, we expect to complete construction and commissioning of Forrest Kerr and tie in to BC Hydro's transmission line in mid-2014. We also plan to make considerable progress at the McLymont Creek and Volcano Creek projects, scheduled to be in service in late 2015. We intend to complete the bridge across the Iskut River and the road to the McLymont Creek intake structure. We will then continue to progress the tunneling and intake structure.

The Northwest Projects will be a significant step-change for our business. We expect them to add approximately $130 million in annual EBITDA, underpinned by 60-year contracts with BC Hydro.

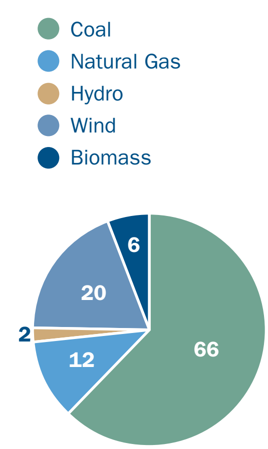
Normalized Operating Income *($ millions)*



Generating Capacity *(MW)*



2012 Fuel Type *(%)*



We expect clean energy to be 59 percent of generating capacity by 2016 with our NW projects.

Utilities

Secure. Regulated. Growing.

With a rate base of over $1.3 billion and five wholly-owned utilities, we serve nearly 550,000 customers across North America.

Assets and Strategy

AltaGas owns and operates utilities that deliver natural gas to end-users in Alberta, British Columbia, Nova Scotia, Michigan and Alaska. Our stable, long-life assets are underpinned by regulated returns that provide predictable earnings and cash flow. The experienced AltaGas team is focused on providing safe, reliable service while increasing rate base through organic growth and major project opportunities.

A Year of Significant Customer and Rate Base Growth

The highlight of 2012 was the $1.14 billion acquisition of SEMCO, the largest acquisition in our history. This transaction increased our stable earnings, grew our customers and rate base, and diversified us into the U.S. market. The utilities added in Michigan and Alaska align with our current geographic footprint and have constructive regulatory regimes.

In 2012, the rate base in our Canadian utilities grew 8 percent. We paved the way for CNG trucking in Nova Scotia and B.C. and began delivering CNG in B.C. to an area not served by pipelines. The greenfield development of Heritage Gas in Nova Scotia and a 20-year system betterment program in our Alberta utility also drove strong growth.

233%
growth in operating income in 2012

$1.3
billion rate base, an $800 million increase over 2011

430,000
new customers added through SEMCO in 2012

With natural gas in abundance in North America, our goal is to find innovative ways to deliver more natural gas to more end users.

Exciting Growth Opportunities

We are undertaking feasibility studies to expand the PNG pipeline and increase natural gas deliveries to Kitimat and Prince Rupert. This could open doors for Canadian natural gas to access Asian markets well ahead of other projects.

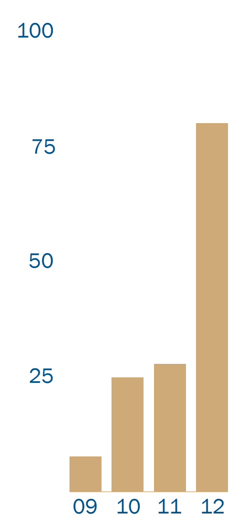
In our Canadian utilities, we expect sustained growth. We will continue to expand the Heritage Gas franchise, realize further benefits from our Alberta system betterment program and continue CNG opportunities. In Nova Scotia, we are building CNG stations and expect to begin service by May 2013. There are also opportunities to grow our U.S. utilities and increase natural gas storage capacity in Alaska. With these exciting opportunities, we plan to invest $500 million in our utilities over the next five years, in addition to pursuing the PNG expansion.

$200 million
EBITDA expected in 2013

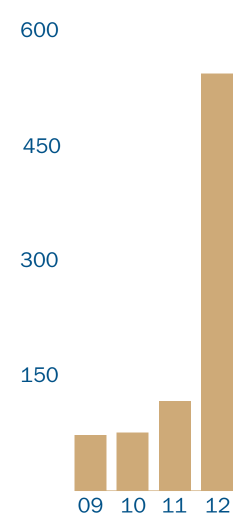
	Canada	U.S.	Total
Km of pipeline	24,899	14,933	39,832
2012 rate base	$0.6 B	US$0.8 B	$1.3 B
Regulated ROE [1]	10.0%	11.3%	–
Approved debt [1]	6.5%	5.6%	–
2013 EBITDA [2]	$70 M	$130 M	$200 M

1 *Average of the utilities in each of Canada and U.S.*
2 *Forecast.*

Normalized Operating Income *($ millions)*



Customers *(thousands)*



Sharing the Journey

Our success is driven by people – in our companies and in the communities where we work and do business. Community relations and social responsibility are an essential part of our journey.

Involving the Community

Our goal is to become trusted partners in the communities where we work and live. We believe in keeping community members informed, listening to their feedback and involving them in our plans. That's why every AltaGas project comes with a commitment to a program of community engagement. When we constructed the Gordondale gas plant, we maintained a dialogue with the community and engaged local neighbours with open house forums and community dinners. AltaGas is also actively involved in hosting and participating in community events throughout our operations including local fishing derbies, community office BBQs, Canada Day celebrations, local conferences, job fairs and more. Whether we are interacting at an open house, a community BBQ or an investor meeting, our willingness to build relationships through open, honest communication and mutual respect brings success to communities, shareholders and AltaGas. We see great value in continuing to strengthen these relationships and build new ones.

Helping Communities Thrive

As we grow our company and meet significant project and financial milestones, we take tremendous pride in helping others succeed as well. This includes communities, social organizations, First Nations partners and employees. In 2012, the AltaGas family assisted over 350 organizations across North America on their own journeys, providing over $1.4 million in financial support and many hours of volunteer time.

AltaGas' HEROIC program encourages employees to take one paid work day each year to volunteer in their communities. The program supports both individual volunteerism and group efforts.

Over
350
organizations across North America supported by AltaGas in 2012

Over
$1.4 million
gifted to community organizations in 2012




In 2012, AltaGas sponsored a day of caring for the United Way incorporating the HEROIC program. AltaGas employees volunteered at the Children's Cottage Society in Calgary for a day and assisted with getting a new facility up and running.

AltaGas' vision supports a culture that contributes to society in many ways. We value diversity in our giving and partner with organizations big and small. We are proud of our relationships with Cross Country Canada, STARS and the United Way and support a wide range of organizations from health and social services to educational, arts and athletic groups.

We are proud of our diverse community involvement:

- AltaGas is donating $50,000 over three years to the Kids Cancer Care Foundation's Camp Kindle, where children and families can escape the rigors of cancer treatment.
- Our natural gas utility in Michigan helped victims of Hurricane Sandy by sending 20 trained personnel to help restore natural gas service to thousands of New Yorkers.
- AltaGas has supported Quest Theatre since 2002, helping them expand their visibility across Alberta and enrich young people's lives through theatre.
- AltaGas was the title sponsor of the Calgary Fetal Alcohol Network Run/Walk.
- AltaGas awarded 10 bursaries and scholarships to deserving Tahltan students in British Columbia.
- Our natural gas utility in Nova Scotia sponsored the Clean Nova Scotia youth summer program, which provides young Nova Scotians hands-on experience in environmental projects.

Safety and Environment

Safety and the environment are core values at AltaGas. We steward the environment and our operations knowing that safety and sound environmental practices are critical to our success.

Supporting a Safe and Healthy Environment

On our journey, we are committed to protecting employees, the public and the environment. The path is one of continuous improvement and we make every effort to identify and minimize impacts along the way. We have management processes and a dedicated board committee that oversees all aspects of environment and safety. Under the committee's direction, considerable effort was made in 2012 to maintain and integrate Environmental and Safety Management systems across our operations, including our recently acquired assets in the U.S. and Canada.

Enhancing Training and Employee Awareness

Safety begins with prevention. We provide safety training that directly relates to all employees' and contractors' work activities. Hazard identification, inspections, procedures and clear communication are key to preventing injuries and are part of this training.

As a growing company, we have facility construction underway across North America. With high levels of activity and many workers, we provided additional safety training to address and reduce the number of construction-related injuries. The success of these efforts is showcased by our Gordondale gas plant. We completed construction of the largest sour gas processing facility built in Alberta in the past 15 years ahead of schedule with no lost-time injuries. While this is impressive, we recognize there is still work to be done in reducing the recordable injuries at construction sites.

1.4

million tonnes

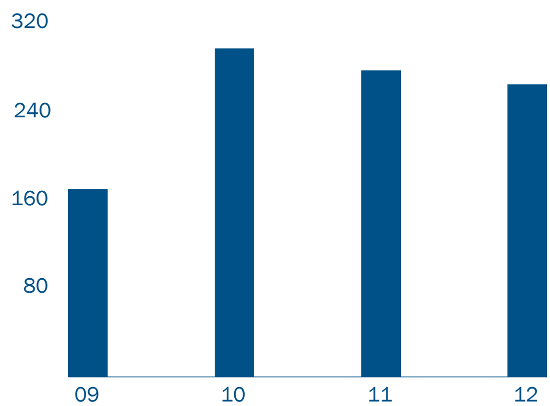
The number of greenhouse gases AltaGas has reduced since 2007

760,000

MWh

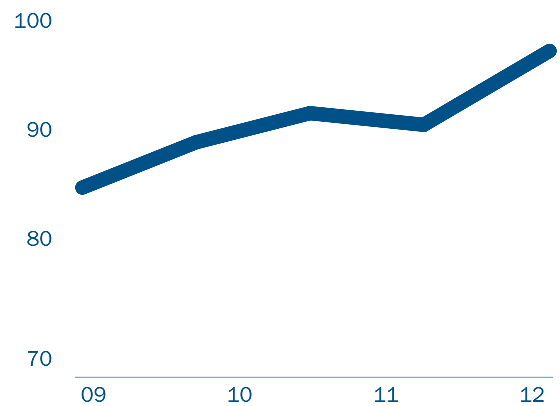
The quantity of green electricity produced by AltaGas-owned facilities since 2009

Vehicle Accident Rate
(thousand kilometres per vehicle accident)



As we integrate our new acquisitions, we will strive to maintain and improve our strong safety performance and foster a safe work environment for all employees.

Health & Safety Audit Scoring *(%)*



In our 13th annual safety audit, we achieved an overall score of 97 percent, a 6 percent increase over 2011. We are proud of this milestone to improve employee safety.

Promoting Public Safety through Asset Integrity

Public safety depends on the structural and operating integrity of our physical assets. In 2012, we conducted an integrity risk assessment of our transmission pipeline network. Based on this assessment we increased our maintenance schedule to reduce the likelihood of spills. In the unfortunate event of an incident, we have the skills and experience needed to respond appropriately.

Reducing Emissions, Growing Renewables

As we grow, AltaGas strives to reduce the emissions intensity of our power generation fleet. We have achieved this reduction through a focus on clean sources of energy, including gas-fired co-generation, wind, run-of-river hydro and biomass assets. In 2012, we added 65 MW of clean power generation assets, reducing our emissions intensity while growing our power portfolio by 13 percent. We plan to further reduce our carbon footprint by adding 277 MW of run-of-river power generation by 2015.

Our performance on spills and releases has remained consistent, while our performance record for greenhouse gas intensity and other air emissions is steadily improving. We are very proud to say that our environmental and safety audit scores have gone up again in 2012. At the same time, we recognize that achieving environmental excellence is a continuous journey – one to which we are strongly committed.

Corporate Governance

David W. Cornhill
Chairman and Chief Executive Officer

Member of the EOHSC

Catherine M. Best
Director

Independent director; Member of the AC

Allan L. Edgeworth
Director

Independent director; Chair of the EOHSC Member of the AC

Hugh A. Fergusson
Director

Independent director; Member of the AC and HRCC

Daryl H. Gilbert
Director

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

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

Myron F. Kanik
Lead Director

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

The members of the Board of Directors of 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 2:30 p.m. MDT on Thursday, April 25, 2013 at Calgary Petroleum Club, Devonian Room, 319 - 5th Avenue S.W., Calgary, Alberta

On behalf of the Board of Directors,

Myron F. Kanik
Lead Director

Statement of Governance Practices

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.**

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 GC is Myron F. Kanik, an energy industry consultant, former President of the Canadian Energy Pipeline Association, and former Deputy Minister in the Alberta Department of Energy.

Audit Committee

The AC consists of five 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 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 AC is Robert B. Hodgins, previously Chief Financial Officer of Pengrowth Corporation, former Treasurer of Canadian Pacific Limited and former 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 and the communities where we operate.

The Chair of the EOHSC 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.

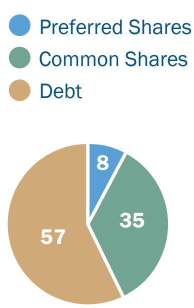
The Chair of the HRCC is Daryl H. Gilbert, a Managing Director with JOG Capital Inc. and prior to that Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd., consultants in reserves evaluation.

Five-Year Financial Highlights

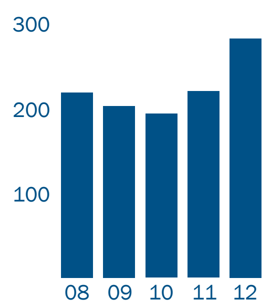
($ millions except as indicated)	2012	2011 [1]	2010 [1]	2009	2008
Revenue	**1,450.3**	1,270.6	1,222.1	1,268.3	1,816.8
Net revenue [2]	**664.6**	513.1	504.8	456.6	476.5
EBITDA [2]	**319.3**	257.2	234.9	247.8	245.4
Normalized EBITDA [2]	**336.9**	265.8	240.2	242.0	245.4
Normalized operating income [2]	**214.1**	175.1	152.2	170.6	178.4
Net income applicable to common shares	**101.8**	82.7	117.0	141.3	163.6
Normalized net income [2]	**109.5**	90.2	101.4	132.8	157.9
Total assets	**5,911.9**	3,556.2	2,743.1	2,628.9	2,132.3
Total long-term liabilities	**3,349.5**	1,637.6	1,225.4	719.1	851.6
Net additions to property, plant and equipment	**1,532.1**	642.6	211.7	486.4	808.0
Dividends declared	**132.8**	112.2	54.1	–	–
Distributions declared	**–**	–	87.0	170.2	147.1
Cash flows					
Normalized funds from operations [2]	**281.0**	219.0	192.7	202.3	216.8
Funds from operations [2]	**254.6**	213.3	191.7	202.3	216.8
Cash from operations	**146.4**	185.4	190.4	184.1	205.2
($ per basic share, except shares outstanding)					
EBITDA [2]	**3.36**	3.06	2.88	3.16	3.57
Normalized EBITDA [2]	**3.55**	3.16	2.95	3.08	3.57
Net income – basic	**1.07**	0.98	1.43	1.80	2.38
Net income – diluted	**1.06**	0.97	1.43	1.79	2.35
Normalized net income [2]	**1.15**	1.07	1.24	1.69	2.30
Dividends declared [3]	**1.40**	1.34	0.66	–	–
Distributions declared [4]	**–**	–	1.08	2.16	2.14
Cash flows					
Normalized funds from operations [2]	**2.96**	2.61	2.36	2.58	3.15
Funds from operations [2]	**2.68**	2.54	2.35	2.58	3.15
Cash from operations	**1.54**	2.21	2.34	2.34	2.99
Shares outstanding – basic *(millions)*					
During the period [5]	**95.0**	84.0	81.5	78.5	68.8
End of period	**105.3**	89.2	82.5	80.3	71.9

1 *Restated to comply with US GAAP.*
2 *Non-GAAP financial measure; see discussion in "Non-GAAP Financial Measures" section of the annual MD&A.*
3 *Dividends declared of $0.11 per common share per month from January 1 until October 27, 2011, $0.115 commencing October 27, 2011 and $0.12 per common share per month commencing September 10, 2012.*
4 *Distributions declared of $0.18 per trust unit and exchangeable unit per month for the first six months of 2010.*
5 *Weighted average.*

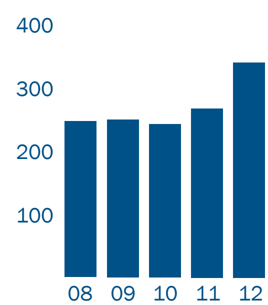
Capital Structure *(%)*



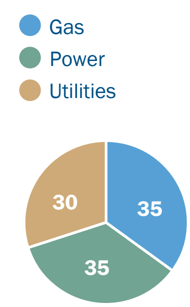
Normalized Funds From Operations *($ millions)*



Normalized EBITDA *($ millions)*



Normalized Operating Income *(%)*



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. (AltaGas or the Corporation) as at and for the year-ended December 31, 2012, compared to the year-ended December 31, 2011. This MD&A dated March 5, 2013, should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of AltaGas as at and for the year-ended December 31, 2012. Effective January 1, 2012, AltaGas follows United States Generally Accepted Accounting Principles (US GAAP). Information derived from the Consolidated Statements of Income and Consolidated Balance Sheets for the year-ended and as at December 31, 2011, along with other selected financial information for 2011 have been restated to comply with US GAAP. All prior comparative information that has been restated to US GAAP is labeled "restated".

This MD&A contains forward-looking statements. When used in this MD&A the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to AltaGas or any 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, opportunities and financial results. Specifically, such forward-looking statements are set forth under: "Consolidated Outlook" and "Growth Capital".

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect AltaGas' current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation, changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in AltaGas' public disclosure documents.

Many factors could cause AltaGas' or any of its business segments' actual results, performance or achievements to vary from those described in this MD&A, including without limitation those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Factors which could cause results or events to differ from current expectations are discussed in the "Risk Management" section of the MD&A and may also include: capital resources and liquidity risk, market risk, commodity price risk, operational risk, volume declines, weather, construction, counterparty risk, environmental risk, regulatory risk and labour relations. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this MD&A herein should not be unduly relied upon. These statements speak only as of the date of this MD&A. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified as cautionary statements.

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

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

ALTAGAS ORGANIZATION

The businesses of AltaGas are operated by AltaGas, AltaGas Holding Partnership, AltaGas Pipeline Partnership, AltaGas Services (U.S.) Inc., AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), and AltaGas Utility Holdings (Pacific) Inc. (collectively the operating subsidiaries).

ALTAGAS' VISION AND OBJECTIVE

AltaGas' vision is to be a leading North American energy infrastructure company with a focus in Canada and the United States. The Corporation'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 assets which provide stable returns. The Corporation's strategy is to capitalize on the supply and demand dynamic for natural gas and power by owning and operating assets in gas, power and utilities in places that provide a strategic competitive advantage. The Corporation focuses on investing in proximity to owned assets and operations that provide stable, regulated, long-life cash flows with opportunities to grow and add additional earnings and cash flow which support further dividend and capital growth.

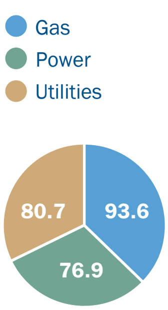
OVERVIEW OF THE BUSINESS

AltaGas is a diversified energy infrastructure business with a focus on natural gas, power and regulated utilities and an enterprise value of approximately $7 billion. 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.

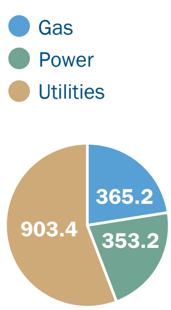
AltaGas has the following three operating segments: Gas, Power and Utilities.

AltaGas' Gas segment serves producers in the Western Canada Sedimentary Basin (WCSB) and touches more than 2 Bcf/d of gas and includes natural gas gathering and processing, Natural Gas Liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing. Gas gathering systems move natural gas from producing wells to processing facilities. The gas is then compressed for transportation. The extraction and field fractionation facilities reprocess natural gas to extract and recover ethane and NGL. The transmission pipelines deliver natural gas and NGL to distribution systems, end-users or other downstream pipelines. AltaGas uses its market knowledge and expertise to create value by providing energy consulting and management services to commercial end-users, buys and resells energy, provides gas transportation, storage and gas marketing for producers and sources gas supply to some of its processing assets. In 2012, construction of AltaGas' 120 Mmcf/d deep-cut Gordondale gas processing facility (Gordondale) was completed and commissioned. The plant is underpinned by a long-term contract with Encana Corporation (Encana) and is equipped with liquids extraction facilities to capture the NGLs value for the producer. In 2012, AltaGas completed expansions at the Blair Creek facility and Marlboro gas processing facilities, adding a combined 44 Mmcf/d of capacity. AltaGas also acquired a 50 percent interest in Quatro Resources Inc.'s

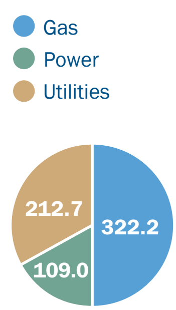
Operating Income
($ millions)



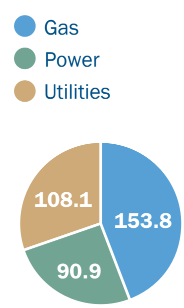
Invested Capital
($ millions)



Net Revenue
($ millions)



EBITDA
($ millions)



(Quatro) midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby gas plant (Gilby Gas Plant). In 2012, construction of the Co-stream facility (Co-stream) at the Harmattan complex (Harmattan) was completed which allows up to 250 Mmcf/d of rich, sweet natural gas sourced from the west leg of the NOVA Gas Transmission Ltd. (NGTL) system to be processed using spare capacity to recover ethane and NGLs. The Co-stream facility provides an opportunity to increase utilization of Harmattan. The new and expanded assets added in 2012 are underpinned by long-term contracts.

The Power segment includes 589 MW of generating power capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets. AltaGas owns 50 percent of the Sundance B Power Purchase Arrangement (PPA), giving it the rights to power output and ancillary services from coal-fired base load generation until December 31, 2020. Further generation is in various stages of construction and development including the Northwest run-of-river projects (Northwest Projects), which consist of the Forrest Kerr run-of-river project (Forrest Kerr Project), McLymont Creek run-of-river project (McLymont Creek Project), and Volcano Creek run-of-river Project (Volcano Creek Project). The 277 MW Northwest Projects are contracted with 60-year Energy Purchase Arrangements (EPA) with BC Hydro which are fully indexed to the Consumer Price Index (CPI), as well as Impact Benefit Agreements (IBA) with the Tahltan First Nation. Forrest Kerr Project is expected to be in service in mid-2014. Mclymont Creek Project and Volcano Creek Project are expected to be in service in late 2015.

The Utilities segment is comprised of natural gas distribution utilities which serve approximately 548,000 customers in Canada and the United States. In Canada, AltaGas owns and operates utility assets that deliver natural gas to end-users in Alberta, British Columbia and Nova Scotia. AltaGas also owns a one-third equity interest in the utility which delivers natural gas to end-users in Inuvik, Northwest Territories. The Utilities segment in Canada is comprised of AltaGas Utilities Inc. (AUI), the Alberta utility, Pacific Northern Gas Ltd. (PNG), the British Columbia utility, Heritage Gas Limited (Heritage Gas), the Nova Scotia utility, as well as a one-third equity interest in Inuvik Gas Ltd. (Inuvik Gas). The utilities are generally allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of capital from the regulator approved capital investment base.

On August 30, 2012, the Corporation acquired all of the issued and outstanding shares of Semco Holding Corporation (SEMCO) for aggregate consideration of US$1.156 billion, including approximately US$371 million in assumed debt. SEMCO is the sole shareholder of SEMCO Energy Inc. (SEMCO Energy), a rate-regulated utility company headquartered in Port Huron, Michigan, with natural gas distribution and natural gas storage operations in Alaska and Michigan. As a result of the SEMCO acquisition, the Utilities segment in the United States is comprised of SEMCO Energy Gas Company (SEMCO Gas) in Michigan and ENSTAR Natural Gas Company (ENSTAR) and a 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska.

STRATEGY

In support of its overarching goal of creating long-term shareholder value and delivering superior economic returns to investors, AltaGas' strategy has remained focused on four key themes:

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

Consistent with its mandate of overseeing and directing the Corporation's strategic direction, the board of directors of AltaGas (Board of Directors) reviews the Corporation's strategy on an annual basis. The Corporation continually assesses the macro-economic and micro-economic trends impacting its business and seeks opportunities to generate value for shareholders, including acquisitions, dispositions or other strategic transactions. Opportunities pursued by AltaGas must meet strategic, operating and financial criteria.

Optimize, Grow and Diversify Energy Infrastructure

The Corporation 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 and power generation. The natural gas and power supply and demand fundamentals in North America have consistently underpinned the Corporation'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 NGL markets are presenting opportunities that the Corporation 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. Increased gas supply, driven by improved drilling technology, continued low natural gas prices in North America and significant natural gas price differential between Asia and North America, have all resulted in increased activity by producers seeking natural gas markets in Asia. There are several liquefied natural gas (LNG) projects under development in British Columbia which could provide significant growth opportunities for each of AltaGas' Gas, Power and Utilities segments. The Corporation is well positioned with internal experience and capabilities to capitalize on the infrastructure requirements across the British Columbia corridor for the LNG projects.

In addition to opportunities to grow from the increased activity in British Columbia as projects develop to export natural gas from Canada's west coast, AltaGas recently entered into a joint venture to directly invest in opportunities to export natural gas and propane from Canada.

Abundant natural gas supply has been 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 use of natural gas for power generation and for use as compressed natural gas (CNG) 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 greenhouse gas emissions. Amid these changing energy supply and demand dynamics, the Corporation's strategy is to diversify and grow its energy asset portfolio with a focus on gas processing, NGL extraction, natural gas, NGL and CNG transmission and distribution, as well as power generation.

Cost management initiatives are balanced with the safe and reliable operation of the Corporation'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. Cost efficiency and operating performance is a driver of increasing value as the Corporation continues to build out its portfolio of assets. Key initiatives continue to increase proficiency in managing costs and 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.

Maintain Financial Strength and Flexibility

Financial discipline is a fundamental cornerstone of the Corporation'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 Corporation has sufficient liquidity to meet its capital requirements, and do so at the lowest cost possible. The Corporation 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 Corporation's stable business model is mitigation of exposure to certain market price risks. As a result, the Corporation 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.

In 2012 the Corporation significantly increased its investment in the United States with the SEMCO acquisition. AltaGas mitigates the foreign exchange exposure on its United States investments by incorporating U.S. denominated capital into its financing strategy.

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 Corporation 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.

STRATEGY EXECUTION

2012 was a milestone-year for AltaGas with the acquisition of SEMCO, construction of the Gordondale deep-cut natural gas processing facility, the completion of the Co-stream facility at Harmattan, the Blair Creek facility expansion, and the construction and start-up of the 29 MW Busch Ranch wind farm (Busch Ranch) in Colorado. The construction of the Northwest Projects is ongoing and continues to proceed ahead of schedule and on budget. Throughout this growth cycle, the Corporation has maintained its financial strength and flexibility through a combination of internally-generated cash flows, the Corporation's dividend reinvestment program (DRIP), and the issuance of $1.2 billion of equity and long-term debt.

The US$1.156 billion acquisition of SEMCO was successfully closed on August 30, 2012. The addition of SEMCO represents a significant step in the execution of AltaGas' strategy and increases stable, regulated cash flows to further support both its dividend and capital growth projects in Canada and the United States. After the acquisition, Utilities customers increased from just over 116,000 to approximately 548,000 along with more than a two-fold increase in rate base to approximately $1.2 billion.

In 2012 AltaGas completed construction of the 120 Mmcf/d Gordondale deep-cut, natural gas processing facility. The plant is located in the Montney resource area, one of the largest, low-cost, liquids-rich resource plays in the WCSB. This plant will allow AltaGas to provide a midstream solution to a number of producers in the area and is underpinned by a long-term natural gas supply contract with Encana.

The Harmattan Co-stream project (Co-stream Project), completed in late 2012, is a great example of AltaGas optimizing its assets. The Co-stream facility uses 250 Mmcf/d of existing spare capacity at Harmattan and is underpinned by a 20-year cost-of-service contract with NOVA Chemicals Corporation (NOVA Chemicals).

The 50 Mmcf/d expansion at the Blair Creek facility was successfully commissioned in third quarter 2012. The expansion is underpinned by long-term contracts with three producers.

The addition of the second 15 MW cogeneration facility (Cogeneration II) at Harmattan, the 3.4 MW Gordondale peaking plant, the 29 MW Busch Ranch wind farm and the recently acquired biomass facilities are examples of AltaGas' ability to provide services that are complimentary to its existing business and grow through acquisition and development of energy infrastructure. AltaGas demonstrated the ability to construct and commission energy infrastructure assets ahead of schedule and on budget. AltaGas owns a 50 percent interest in the 29 MW wind project with the local utility Black Hills/Colorado Electric Utility Company LP (Black Hills Energy). The power generated is sold pursuant to a 25-year renewable energy purchase agreement with Black Hills Energy. In total AltaGas added 65 MW of new power assets in 2012, increasing total power generation capacity by 13 percent. 50 MW or almost 80 percent of the new generation capacity added in 2012 was renewable.

Significant progress was made in 2012 on the three run-of-river power generation projects which make up the approximately $1 billion investment in the Northwest Projects. Construction of the 195 MW Forrest Kerr Project is ahead of schedule and on budget. All material permits for the start of construction on the 66 MW McLymont Creek Project and the 16 MW Volcano Creek Project have been issued. AltaGas has 60-year EPAs with BC Hydro which are fully indexed to the CPI as well as IBAs with the Tahltan First Nation for the Northwest Projects. Under the terms of the EPAs, AltaGas will sell all the power generated from the Northwest Projects to BC Hydro. Together the Northwest Projects add a significant stream of stable, long-term cash flow that supports AltaGas' objective of providing shareholders with stable and predictable cash flows for generations.

In 2012, AltaGas completed several financing transactions demonstrating its ability to execute its strategy of maintaining financial strength and flexibility. The Corporation extended its debt maturity profile with two senior medium-term note (MTN) issuances for a total of $550 million and extended the term of the $600 million and $75 million credit facilities to four-years to May 30, 2016. AltaGas also completed a US$200 million preferred share issuance and a $403.5 million common share issuance. At the end of 2012, AltaGas had approximately $772 million of available credit facilities and debt-to-total capitalization of 57.4 percent.

In third quarter 2012, AltaGas announced that beginning in October 2012 the monthly dividend would increase by 4.3 percent to $0.12 per share. The dividend increase reflects the success of AltaGas' recent acquisitions and the progress AltaGas has made on its major projects as well as the strength and stability of its cash flows.

A significant element of capitalizing on opportunities to grow is the ability to pursue new markets for Canadian natural gas, more specifically, natural gas from the WCSB where AltaGas operates. On January 28, 2013, AltaGas signed an agreement with Idemitsu Kosan Co., Ltd. (Idemitsu) to form the AltaGas Idemitsu Joint Venture Limited Partnership (AltaGas Idemitsu LP). AltaGas Idemitsu LP plans to pursue opportunities involving exports of LNG and liquefied petroleum gas (LPG or propane) from Canada to Asia. AltaGas and Idemitsu will each own a 50 percent interest in AltaGas Idemitsu LP.

AltaGas Idemitsu LP plans to pursue opportunities to develop long-term natural gas supply and sales arrangements to meet the growing demand for natural gas in Asia. As Asia's largest LNG consumer, Japan would benefit from a new and dependable source of LNG. LNG from Canada would provide a clean, stable, and reliable source of energy to meet Japan's growing demand for natural gas. The development of a Canadian LNG export opportunity would also provide long-term benefits to Canadians at a time when Canada is seeking to diversify its energy markets.

AltaGas Idemitsu LP will also undertake feasibility studies for the development and construction of liquefaction facilities as part of the proposed project to export LNG to markets in Asia. The feasibility study is expected to be completed by early 2014. The pipeline capacity required to transport natural gas to the liquefaction facility is expected to be provided by AltaGas' wholly owned subsidiary PNG. Subject to consultations with First Nations, and the completion of the feasibility study, permitting, regulatory approvals and facility construction, the proposed LNG exports could begin as early as 2017.

AltaGas Idemitsu LP also plans to pursue opportunities to develop a LPG export business, including logistics, plant refrigeration and storage facilities. The feasibility study is expected to be completed in 2013. Idemitsu is a shareholder of Astomos Energy Corporation, one of the world's largest LPG suppliers. Subject to consultations with First Nations, and the completion of the feasibility study, permitting, regulatory approvals and facility construction, the proposed LPG export business could begin as early as 2016.

2012 GROWTH HIGHLIGHTS

AltaGas:

- Closed the acquisition of SEMCO, the largest acquisition in AltaGas' 18-year history. After the acquisition, Utilities customers increased from just over 116,000 to approximately 548,000, along with more than a two-fold increase in rate base;
- Commissioned the 120 Mmcf/d Gordondale gas plant and began commercial operations at the facility which serves producers in the Montney gas resource area and includes liquids extraction facilities to capture NGL;
- Completed construction of the intake structure for the Forrest Kerr Project, with powerhouse and in-river work well underway. Construction is expected to be fully completed by the end of 2013, with commissioning to follow based on the availability of the Northwest Transmission Line (NTL);
- Completed construction of the Co-stream facility which began commercial operations in late 2012, expanding AltaGas' extraction capability and further utilizing Harmattan;
- Acquired and commissioned a 50 percent interest in the 29 MW Busch Ranch in Colorado ahead of schedule;
- Commissioned the 50 Mmcf/d expansion of the Blair Creek facility;
- Closed the acquisition of Decker Energy International Inc. (DEI) which added 35.1 MW of biomass generation to AltaGas' portfolio;
- Increased rate base at both AUI and Heritage Gas by 11 percent;
- Started developing a CNG distribution system at Heritage Gas which will allow customers not connected through the distribution infrastructure to gain access to natural gas; and
- Began delivering CNG to a mine in a remote area of British Columbia.

2012 FINANCIAL HIGHLIGHTS

AltaGas:

- Completed the issuance of 13,915,000 common shares on August 30, 2012, resulting in gross proceeds of $403.5 million;
- Completed a $350 million issuance of senior unsecured MTNs on September 28, 2012. The notes carry a coupon rate of 3.72 percent and mature on September 28, 2021, the longest maturity and lowest interest rate MTNs ever issued by AltaGas;
- Completed the issuance of 8,000,000 five-year rate reset preferred shares, Series C (the Series C Preferred Shares) on June 6, 2012, at a price of US$25 per Series C Preferred Share, for aggregate gross proceeds of US$200 million;
- Completed a $200 million issuance of senior unsecured MTNs on April 13, 2012. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020;
- Extended the term of the $600 million and $75 million credit facilities to four-years to May 30, 2016;
- Reported net income applicable to common shares of $101.8 million ($1.07 per share) in 2012 compared to $82.7 million ($0.98 per share) in 2011;
- Reported normalized net income [1] of $109.5 million ($1.15 per share) in 2012 compared to $90.2 million ($1.07 per share) in 2011;
- Reported normalized EBITDA [1] of $336.9 million in 2012, compared to $265.8 million in 2011;
- Reported normalized funds from operations [1] of $281.0 million ($2.96 per share) in 2012, compared to $219.0 million ($2.61 per share) in 2011;
- Reported net debt as at December 31, 2012, of $2,690.5 million, compared to $1,334.2 million as at December 31, 2011; and
- Reported net debt-to-total capitalization ratio as at December 31, 2012, of 57.4 percent, compared to 49.5 percent as at December 31, 2011.

CONSOLIDATED OUTLOOK

AltaGas expects to report stronger earnings in 2013 compared to 2012 due to new and expanded assets added primarily in the second half of 2012. The new and expanded assets include the Gordondale and Co-stream gas processing facilities added in December, the Busch Ranch wind farm added in October, the natural gas distribution utilities acquired in August, the Blair Creek expansion added in August, the gas-fired power assets constructed and the Gilby Gas Plant acquired in July, and the biomass assets acquired in January. Earnings may however be negatively impacted if current forward curves for frac spreads and power prices in Alberta materialize and producers continue to reduce drilling activity as a result of low natural gas prices.

AltaGas expects significant seasonality in 2013 results as SEMCO contributes its first full year of earnings. Utilities earn most of their income in the first and fourth quarters in the heating seasons. Starting in 2014, AltaGas expects the seasonality to be offset with cash flows from the Forrest Kerr Project, as run-of-river projects earn most of their income in the second and third quarters from winter run-off. Together these assets result in lower seasonality of earnings, providing investors with stable and predictable cash flow year round.

Results in 2013 for the Utilities segment is expected to be stronger than 2012, driven mainly by the acquisition of SEMCO. In 2013 SEMCO is expected to generate approximately $130 million of EBITDA on a weather normalized basis. The Canadian utilities are expected to increase earnings in 2013 through a forecasted rate base growth of approximately nine percent.

SEMCO Gas is expected to apply for updated rates in 2014 or later. ENSTAR is expected to apply for updated rates in 2014. In 2013 AUI will begin its first of five years under performance-based regulation whereby its rates will be adjusted annually based on the prior year's rates for inflation, productivity, exogenous events, extra-capital invested and other factors. PNG has applied to its regulator for updated rates for 2013. Heritage Gas is expected to apply for updated rates in 2014.

In addition to growing its regulated natural gas distribution network, Heritage Gas is developing a CNG trucking network in Nova Scotia. The Nova Scotia government has adopted a hybrid approach to regulation of CNG distribution in the province which allows non-rate-regulated entities to participate in a portion of the market. Heritage Gas has contracted to commence delivery to its first customer in May 2013 and expects to operate its CNG business initially on an unregulated basis until regulations are finalized.

1 *Includes Non-GAAP financial measures. Please see discussion in Non-GAAP financial measures in this MD&A.*

In 2013, earnings and throughput at AltaGas' processing facilities are expected to be higher than 2012. Volumes are expected to grow from the 2012 additions of new and expanded assets. Specifically, the Gordondale gas plant, the Co-stream facility at Harmattan, the Blair Creek expansion, and the acquired 50 percent interest in the Quatro midstream assets, including its 87 percent interest in the Gilby Gas Plant. These new assets are primarily underpinned by long-term take-or-pay commitments from AltaGas' customers resulting in no incremental direct exposure to commodity prices from these new revenue streams.

The Co-stream facility is expected to add approximately $28 million in EBITDA and is underpinned by a 20-year cost-of-service agreement with NOVA Chemicals. The Gordondale gas plant is underpinned by a take-or-pay contract with Encana for a portion of the capacity. AltaGas is working with producers in the liquids-rich area of the Montney and expects to ramp up throughput at the facility over the course of 2013. The facility is currently operating at approximately 40 percent utilization. The Blair Creek expansion is currently operating at approximately 75 percent utilization. In 2013, more than half of the throughput volumes for the field processing business is anticipated to be captured through facilities near or inside Montney, Wilrich, Notikewin, Glauconite, Duvernay and other liquids-rich gas formations, along with associated gas from oil or solution gas production. AltaGas expects increased volumes from the new and expanded facilities to offset the impact of low producer activity as a result of low natural gas prices. There are no major turnarounds planned in the Gas segment in 2013.

Management estimates that 11 percent of total extraction volumes in 2013 will be exposed to frac spread. In 2013, approximately 45 percent of frac exposed volumes have been hedged at approximately $30/Bbl.

The Power segment is expected to report comparable earnings in 2013 to those of 2012. Increased earnings from assets acquired and completed in 2012 are expected to be offset by the impact of lower power prices in Alberta if the current forward curve for power in Alberta materializes.

For first quarter 2013, AltaGas has hedged approximately two-thirds of volumes exposed to Alberta power prices at an average price of $67/MWh. For the second through fourth quarters of 2013, AltaGas has hedged approximately 40 percent of volumes exposed to Alberta power prices at an average price of $64/MWh. On a full year basis, AltaGas is approximately 50 percent hedged at an average price of $65/MWh. Management expects to be able to continue to execute short-term hedges throughout the year at premium prices to the medium and long-term power prices as reflected in the current forward curves.

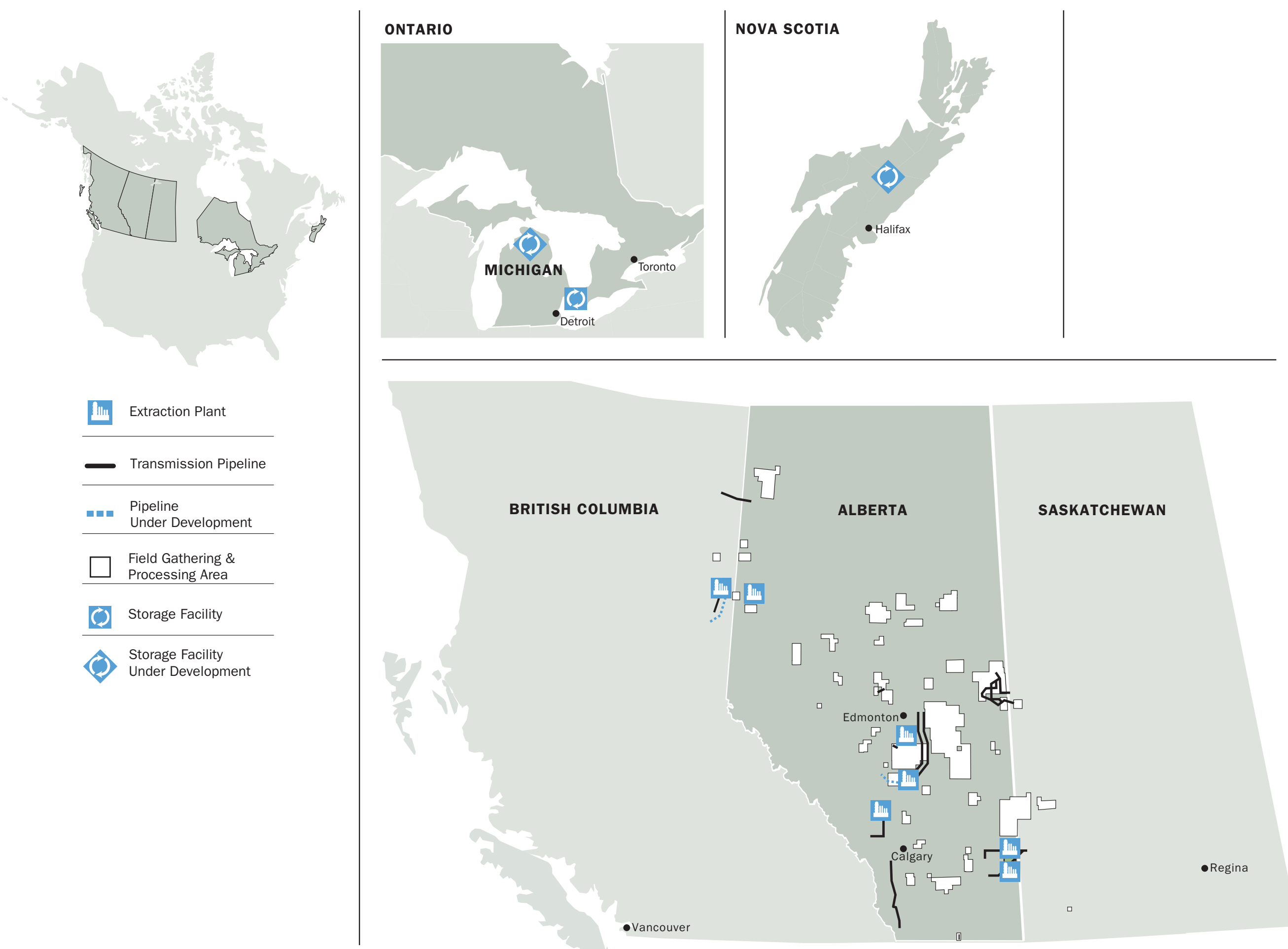
While the Corporation expects certain of the regulated utilities to pay cash tax in 2013, the Corporation has approximately $1.8 billion in tax pools, and based on current estimates for capital expenditures and taxable income, AltaGas does not expect to be materially cash taxable until 2017.

GAS

Description of Assets

AltaGas' Gas segment serves customers primarily in the WCSB and touches more than 2 Bcf/d of natural gas including natural gas gathering and processing, NGL extraction and fractionation, transmission, storage, natural gas marketing and energy management. 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 NGL. AltaGas owns 1.6 Bcf/d of extraction processing capacity and 1.4 Bcf/d of raw field gas processing capacity.

Transmission pipelines deliver natural gas and NGL 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 commercial 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 segment also includes several expansion and greenfield projects under development and construction.



The Gas segment includes:

- Interests in six NGL extraction plants with net licenced inlet capacity of 1.6 Bcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues;
- Four natural gas transmission systems with combined transportation capacity of approximately 0.5 Bcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d. The transmission assets provide stable take-or-pay based revenues;
- More than 70 gathering and processing facilities in 32 operating areas in western Canada and a network of 6,600 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. The field facilities provide fee-for-service revenues based on volumes processed. A significant portion of contracts flow through operating costs;
- The recently completed Gordondale facility with deep-cut extraction capabilities and the Co-stream facility which provide opportunity for the growth of liquid-rich gas processing and NGL extraction services. The facilities earn revenue on a take-or-pay or cost-of-service revenue model;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn Hub in eastern Canada;
- Interests in natural gas storage development projects in Nova Scotia, Michigan and Alaska; and
- Energy consulting, natural gas purchases and sales and gas transportation services to optimize the value of the infrastructure assets and meet customer needs.

Capitalize on Opportunities

AltaGas pursues opportunities in the Gas segment to deliver value to its customers and enhance long-term shareholder value. The Corporation's objectives are to:

- Increase throughput, utilization and efficiency of existing facilities;
- Provide the most cost-effective midstream services while delivering reliable and safe operations;
- Mitigate volume risk by directly recovering operating costs from customers and employing other contractual arrangements to mitigate the impact of declining volumes;
- 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.

The Gas segment provides safe and reliable natural gas and liquids gathering, processing, extraction, transportation and storage services to its customers. The strategic focus is to increase profitability of the existing infrastructure, expand and add new infrastructure, and redeploy assets to capitalize on increased exploration and drilling activities in the WCSB. AltaGas also focuses on long-term, fixed-fee, take-or-pay 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 WCSB. 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 WCSB. 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 WCSB. 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 natural gas and oil, thereby increasing the demand for processing capacity that allows producers to earn higher netbacks on liquids-rich gas and associated gas from increasing oil production.

The supply and demand fundamentals for natural gas and NGL provide significant growth opportunities in the Corporation's Gas segment. 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. AltaGas' results within the gas processing business unit have demonstrated this market behavior.

The natural gas supply to AltaGas' extraction plants, with the exception of Harmattan and Younger Extraction Plant (Younger), 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. Natural gas supply to Younger is dependent on the amount of raw natural gas processed at the McMahon gas plant, which is based on the robust natural gas producing region of northeast British Columbia. Harmattan's raw natural gas supply is based on producer activity 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. Harmattan is the only deep-cut and fractionation plant in the area. There is significant demand for gas processing capacity at the Harmattan plant as a result of the high volume of liquids-rich gas being produced in the area. The Co-stream facility is an example of optimizing and growing the existing assets while increasing the utilization at the existing plant. The 20-year cost-of-service arrangement with NOVA Chemicals for the Co-stream facility at Harmattan adds long-life, 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 gas processing. The Corporation 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 its competitive advantage. The strategic location of some of its existing infrastructure is expected to allow the Corporation to capitalize on growing natural gas production in northeast British Columbia and northwest Alberta, in response to the development of unconventional sources of gas, such as Montney and Duvernay shale gas plays. In addition, AltaGas is able to relocate certain units quickly and cost effectively to respond to the changing processing needs of its customers since field gas compression and processing units are mostly skid-mounted. The new Gordondale gas 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. The contractual underpinning of the Gordondale facility provides stable cash flows. Overall, the diverse nature of its natural gas and NGL infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

Due to the integrated nature of AltaGas' gas gathering and processing 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 end-user demands. AltaGas pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure based businesses. These include maintaining the cost-effective flow of gas through extraction plants and increasing services provided to producers. AltaGas has significant gas and power 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.

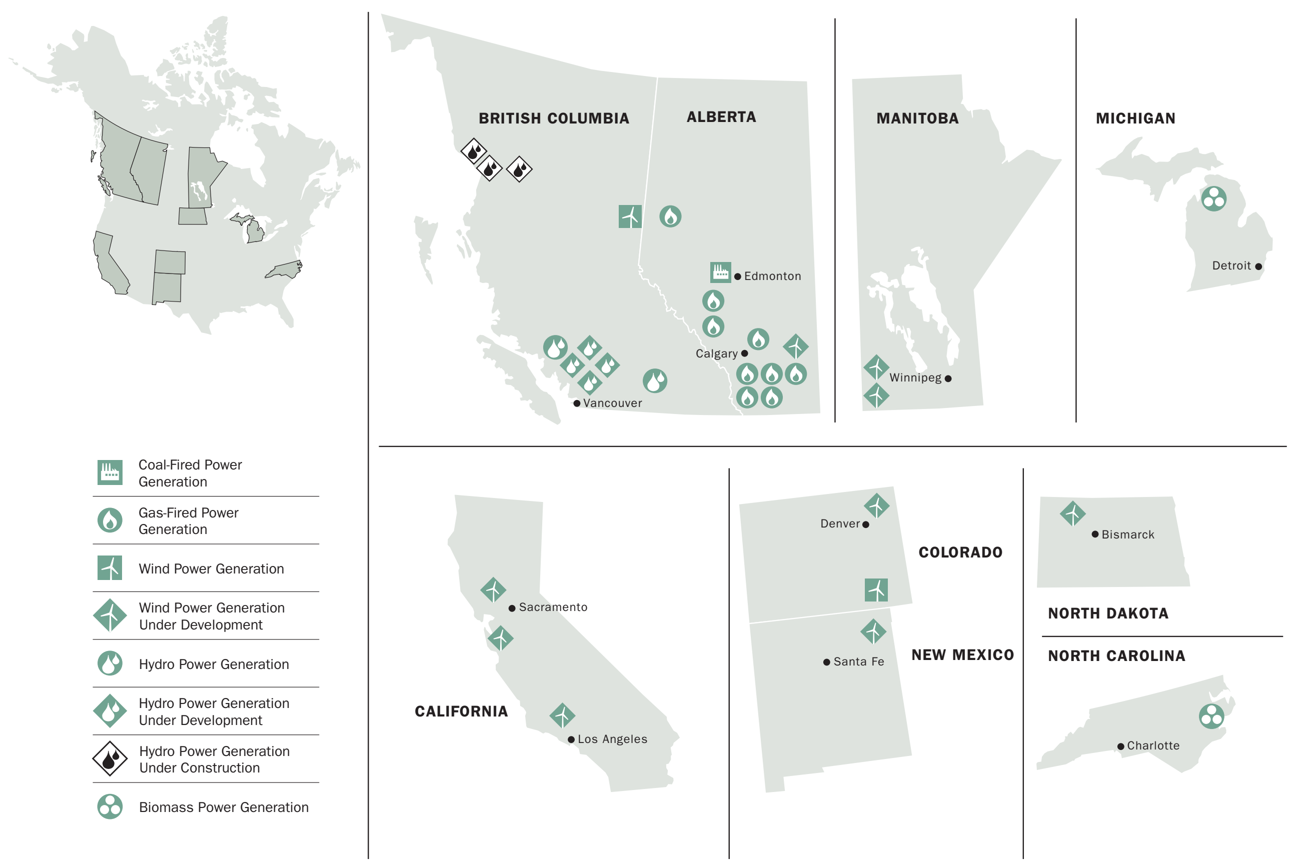
POWER

Description of Assets

The Power segment includes 589 MW of generating capacity from coal-fired, wind, gas-fired, biomass and run-of-river assets. Further power generation of 1,611 MW is in various stages of construction and development including 277 MW for the Northwest Projects.

The Power segment includes:

- 353 MW of coal-fired generating capacity in Alberta through the Sundance B PPAs. AltaGas employs an economic hedging strategy to mitigate the exposure to spot power prices;
- 116.5 MW of wind generation and a further 1,293.5 MW in various stages of development. All operating wind generation is sold via long-term EPAs;
- 42.4 MW of gas-fired peaking plants and a further 30 MW of cogeneration capacity. These gas-fired facilities in Alberta provide partial backstopping to the Sundance B PPAs;
- 35.1 MW of biomass generation in the United States. The plants have long-term EPAs with strong counterparties;
- 11.6 MW of operating run-of-river generation, a further 277 MW under construction, and 40 MW under development. All run-of-river have long-term EPAs; 277 MW of the generation has 60-year EPAs; and
- Commercial and Industrial (C&I) power sales in Alberta which provide further opportunities to hedge power prices in Alberta for periods of one to five-years.



At the end of 2012, the Power segment totalled 425 MW of power generation capacity in Alberta. AltaGas' 50 percent ownership of the Sundance B PPAs represents the majority of AltaGas' generation in Alberta. The PPAs provide AltaGas with the rights to power output and ancillary services from 353 MW of coal-fired base load generation until December 31, 2020. The 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 the marketing of output.

In addition, AltaGas has 42.4 MW of gas-fired peaking plants and 30 MW of cogeneration capacity. This 72.4 MW of gas-fired capacity provides fuel diversity to AltaGas' Power segment and partially backstops outages at Sundance. Cogeneration units provide steam to the gas processing facilities 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 Corporation employs a power economic hedging strategy which is designed to balance market and operational risk related to the Sundance PPAs, thereby reducing the exposure to Alberta spot power prices and providing earnings stability in the Power segment. AltaGas also sells power to C&I end-users in Alberta, providing further earnings stability. Counterparties are subject to credit reviews and credit thresholds in the normal course of business.

AltaGas recognizes that climate change concerns give rise to opportunities to create value. The Corporation is committed to capturing and retaining that value for its shareholders. AltaGas tracks and maintains its inventory of emissions 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.

AltaGas owns 113.6 MW of power generation in British Columbia. The 102 MW Bear Mountain wind park (Bear Mountain) near Dawson Creek, British Columbia, generates green attributes and Renewable Energy Certificates (RECs) which AltaGas has retained. These credits have been certified by the California Energy Commission, enabling AltaGas to sell them in the California market. In addition, Bear Mountain receives $10/MWh for generation through 2019 from the Government of Canada's ecoEnergy renewable initiative (eRPI). AltaGas has a long-term service agreement with the manufacturer of the Bear Mountain wind turbines to operate and maintain the turbines. Also included in the portfolio of power generation assets in British Columbia is a wholly owned 9.8 MW of run-of-river power generation facility and a 25 percent effective interest in a 7 MW run-of-river facility. All power generation assets in British Columbia are underpinned by inflation adjusted long-term EPAs with BC Hydro.

Growth in the Power segment aligns with AltaGas' strategy of increasing earnings and cash flow stability and predictability. AltaGas' most significant undertaking to date is the construction of the 277 MW Northwest Projects. The Northwest Projects, estimated to cost $1 billion, are underpinned by 60-year EPAs, fully indexed to CPI and have IBAs with the Tahltan First Nation. The 195 MW Forrest Kerr Project is progressing well and is ahead of schedule and on budget. The total project is approximately 75 percent complete. Completion of the powerhouse and the in-river work are progressing ahead of schedule. Construction of the Forrest Kerr Project is expected to be completed by the end of 2013. The Forrest Kerr Project is expected to be in service mid-2014, based on the availability of the NTL. All material permits for construction for the two smaller projects - 66 MW McLymont Creek Project and 16 MW Volcano Creek Project - have been issued. Construction of the McLymont access road and bridge work is expected to be completed in the first half of 2013. The detailed engineering for the two smaller projects are underway and will be completed by the end of the first and second quarters of 2013, respectively. The two projects are expected to be in service in late 2015.

In the United States, AltaGas owns 49.5 MW of fully contracted renewable power generation. This includes a 30 percent working interest in the 37 MW Grayling Generating Station, a wood biomass facility in Michigan, and a 50 percent working interest in the 48 MW Craven County wood biomass power facility in North Carolina. Both biomass facilities have long-term PPAs. The Corporation also owns a 50 percent interest in Busch Ranch located in Colorado which has a 25-year EPA.

Capitalize on Opportunities

AltaGas pursues opportunities in the Power segment to enhance long-term shareholder value. The Corporation's 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 across its entire fleet of power generating assets;
- Identify and execute opportunities to create value from the regulation of greenhouse gas emissions;
- Acquire and develop power infrastructure in Canada and the United States 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 Corporation 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 addresses climate change legislation and utilities are faced with renewable portfolio standards. Although coal-fired generation is still the dominant fuel source for power generation in North America, it is decreasing in market share but is doing so based on economic fundamentals. Decreasing natural gas costs have made it such that gas-fired generation can compete on a marginal cost basis with coal in many parts of the United States. The economic benefit of gas-fired generation is amplified when capital costs and dispatch flexibility are taken into account.

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 announced on January 30, 2013, companies that offer the RRO will be allowed to buy electricity up to 120 days in advance, as opposed to the 45-day lead time currently in effect. This change may reduce sudden price spikes for consumers. 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. The RRO pricing mechanism has lowered liquidity in the long-term market. While the changing market dynamics have presented opportunities for AltaGas to capitalize on the short-term price volatility, the RRO pricing mechanism results in fewer opportunities to enter into long-term hedges.

AltaGas' primary means of securing long-term power sales is through its C&I power retail business. AltaGas actively markets electricity and gas directly to end-users, enabling the Corporation 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 100 MW of fixed price sales to C&I customers for 2013, 110 MW for 2014, 90 MW for 2015, and 25 MW for 2016, all with average prices in the low $60's per MWh, excluding retail fees.

Power generated from Bear Mountain is not currently exposed to power price volatility as the power generated is sold to BC Hydro at a fixed price for 25 years with 50 percent escalated by CPI. The British Columbia power market is established by the government's strategy to increase its green footprint and enter into EPAs with independent power producers. While the British Columbia power market is linked to some of the northwest electric regions, namely mid-Columbia and the California Oregon Border 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/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 with the growing North American demand for cleaner energy sources such as natural gas, hydroelectric and wind. The federal government of Canada'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. Bear Mountain, Busch Ranch, Grayling Generating Station, Craven County wood biomass power facility, and the Northwest Projects under construction are all examples of AltaGas' strategy in action.

AltaGas has approximately 1,334 MW of renewable power under development, including 1,293.5 MW of wind power developments, 40 MW of run-of-river hydroelectric developments and 277 MW run-of-river hydroelectric under construction. The wind projects are geographically dispersed in western North America, with 612 MW in Canada and 681.5 MW in the northern and western United States, while the run-of-river projects are located in British Columbia.

In 2012 there was considerable progress made in the natural gas industry in developing LNG projects in western Canada. The potential for large LNG export facilities is expected to require significant power generation to support the LNG facilities and the increased economic and industrial activity expected to occur in the region. The strategic location of AltaGas' assets and operational expertise, along with a track record of collaborating with the First Nations in British Columbia, provide AltaGas a significant competitive advantage in its ability to capitalize on opportunities to increase its power generation portfolio to support LNG activities as they materialize.

UTILITIES

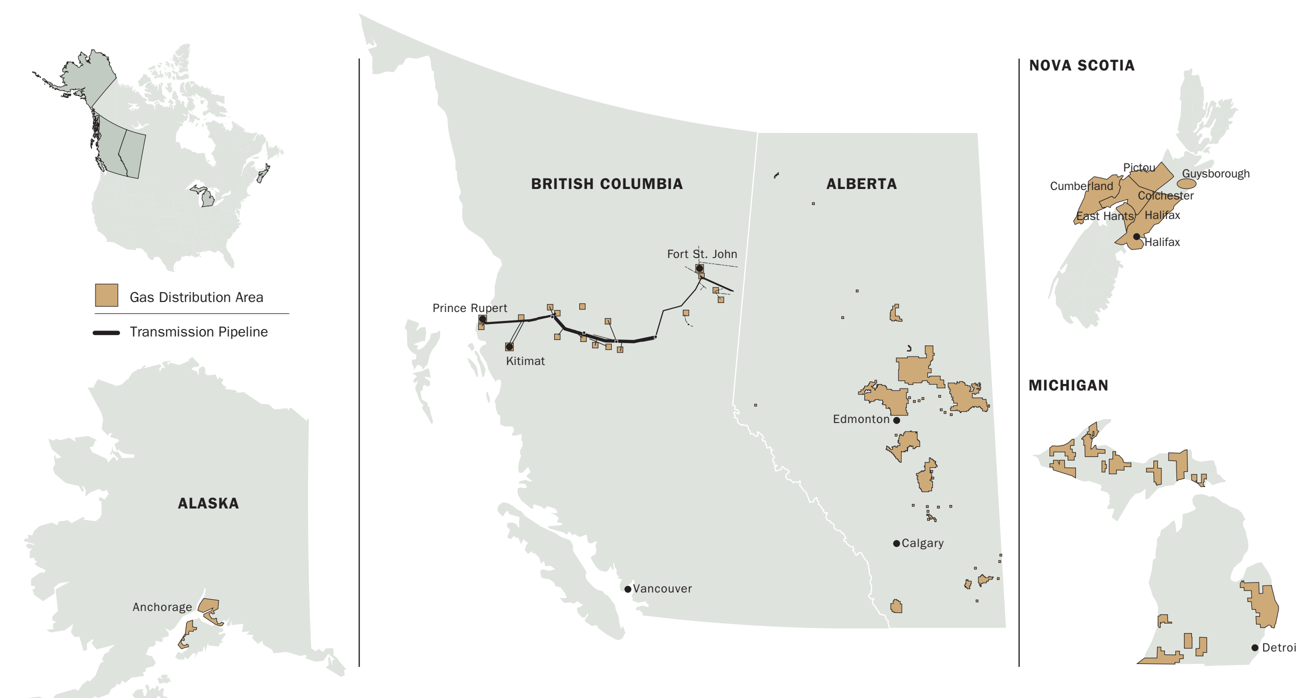
Description of Assets

AltaGas owns and operates utility assets that deliver natural gas to end-users in Alberta, British Columbia, Nova Scotia, Michigan and Alaska. AltaGas also owns a one-third equity interest in the utility which delivers natural gas to end-users in Inuvik, Northwest Territories.

The stable, long-life energy infrastructure is underpinned by regulated returns and regulatory regimes that generally provide stable earnings and cash flows. The Utilities segment enhances the diversification of AltaGas' portfolio of energy infrastructure assets and strengthens the Corporation's business profile, thus allowing the Corporation to meet its objective of generating superior economic returns by operating investments in regulated, long-life assets with stable earnings.

In 2012, AUI in Alberta, PNG in British Columbia, Heritage Gas in Nova Scotia, SEMCO Gas in Michigan, and ENSTAR and CINGSA in Alaska operated in regulated market places where they are allowed the opportunity to earn regulated returns. This return on rate base comprises regulator allowed financing costs and return on equity. In a cost-of-service regime, if actual costs are different from those approved, the utility bears the risk of this difference other than for certain costs that are subject to deferral treatment. Inuvik Gas in the Northwest Territories 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 Utilities segment are 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. In Alberta, Nova Scotia, Michigan and Alaska, 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 delivered volumes and hence actual earned returns for the Utilities business.



Capitalize on Opportunities

The Utilities segment pursues opportunities to enhance long-term shareholder value and deliver value to its customers. The Corporation's objectives for the Utilities segment are to:

- Grow its existing utility infrastructure through infill and expansion of services within current franchise or certificate areas;
- Continue to upgrade the delivery systems within each utility to maintain public and worker safety, and to ensure reliable and efficient long-term operation of the gas delivery systems;
- Develop CNG opportunities;
- 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 in the United States.

Semco Holding Corporation

On February 1, 2012, AltaGas announced the acquisition of SEMCO. The acquisition closed on August 30, 2012, for US$1.156 billion (before adjustments) including US$371 million in assumed debt. During second quarter 2012, AltaGas received final approval from the Michigan Public Service Commission (MPSC) for the SEMCO acquisition. Approval from the Regulatory Commission of Alaska (RCA) for the SEMCO acquisition was received in August 2012.

SEMCO holds, through a wholly owned subsidiary, a regulated natural gas distribution utility in Alaska (ENSTAR) and a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska. SEMCO also holds, through this wholly owned subsidiary, a regulated natural gas distribution utility (SEMCO Gas) and an interest in a regulated natural gas storage facility in Michigan.

At the end of 2012, SEMCO Gas and SEMCO Energy's Michigan non-regulated businesses had approximately 296,000 customers and ENSTAR had approximately 134,000 customers (both including transportation and non-regulated business lines). Of these customers, approximately 91 percent are residential. In 2012 SEMCO Gas and ENSTAR experienced customer growth of 0.4 and 1.0 percent, respectively.

The rate base at year-end was approximately US$430 million for SEMCO Gas, approximately US$227 million for ENSTAR and US$100.4 million for CINGSA (AltaGas' 65 percent share).

In December 2012 SEMCO Gas filed an application with the MPSC seeking to amend the Main Replacement Program (MRP) effective in 2013 and the related MRP surcharge which recovers the incremental capital costs associated with the MRP. SEMCO Gas is proposing to double the amount spent annually on the MRP from US$4.4 million to US$8.8 million by doubling the miles of gas main replaced from 13 miles to 26 miles. If approved, SEMCO Gas expects to increase its MRP surcharge to recover the additional costs of the MRP amendment.

In 2012, the approved regulated return on equity (ROE) for SEMCO Gas was 10.35 percent on 50 percent equity, while the approved regulated return for ENSTAR was 12.55 percent on 51.4 percent equity and the approved regulated rate-of-return for CINGSA was 12.55 percent on 50 percent equity.

SEMCO Gas is expected to make application for updated rates in 2014 or later. ENSTAR is expected to apply for updated rates in 2014. SEMCO Gas, ENSTAR and CINGSA operate under cost-of-service regulation and utilize actual results from the most recent completed fiscal year along with known and measureable changes in their application for new rates.

AltaGas Utilities Inc.

AUI serves approximately 73,500 customers (2011 – approximately 72,000). AUI's customers are 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. Customer growth in 2012 was approximately two percent.

AUI serves almost all of the potential market in its existing service areas. New service site installations during 2012 were 1,730 compared to 1,308 in 2011. In addition to capital expansion for new business and general plant, AUI spent $8.2 million in 2012 on its multi-year system rejuvenation program. This 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 and sixth decade of service. AUI's capital investments grew its 2012 year-end rate base by $18.9 million or approximately 11 percent to $186.4 million.

For 2012, AUI's approved regulated ROE was 8.75 percent (2011 – 8.75 percent) on a prescribed capital structure of 43 percent equity and 57 percent debt. AUI is regulated by the AUC.

Although in 2012 AUI operated under traditional cost-of-service regulation it received the Performance Based Regulatory (PBR) decision in September 2012. The decision set out the AUC's determinations about the form of PBR regulation that will be employed by Alberta electric and natural gas distribution companies beginning in 2013 in place of the existing cost-of-service regulatory system. The initial PBR term will last for five-years and the AUC will make a determination at the end of the initial term as to how it will proceed for future years. Under the new PBR framework, utility rates will be set using a formula that adjusts the prior year's rates for inflation, productivity, exogenous events, extra capital invested and other factors. The PBR framework is intended to incentivize utilities to be more efficient.

The AUC plans to review the equity returns and capital structure of all utilities in Alberta and will hold this Generic Cost of Capital proceeding in 2013 with new rates and capital structure applicable in that year.

Pacific Northern Gas Ltd.

On December 20, 2011, AltaGas closed the acquisition of PNG for total consideration of $224 million including $86 million of assumed debt. The acquisition increased AltaGas' regulated rate base by approximately 50 percent to more than $500 million. The acquisition is consistent with AltaGas' strategy of building one of North America's leading energy infrastructure companies underpinned by stable, long-life assets. PNG operates a transmission and distribution system in the west central portion of northern British Columbia (Western System) and in the areas of Dawson Creek and Fort St. John of northeast British Columbia (Northeast System). PNG serves a base of nearly 34,600 residential customers. The total customers (both transmission and distribution) at the end of 2012 were approximately 39,900 with PNG experiencing customer growth of 0.8 percent per year 2012. PNG's residential customers comprised approximately 87 percent of its total customers.

PNG's regulated rate base was $175.5 million at the end of 2012.

For 2011 and 2012, PNG's weighted average approved regulated ROE was 10.09 percent on a weighted average prescribed capital structure of approximately 44 percent equity and 56 percent debt. PNG is regulated by the British Columbia Utilities Commission (BCUC). On November 30, 2011, PNG filed its 2012 General Rate Application (GRA) and on December 7, 2011, the BCUC approved interim rates as requested in the application. PNG filed an update to the GRA on March 15, 2012, to reflect its new forecast of 2012 costs based on its acquisition by AltaGas. A decision on the western portion of the system was received on September 21, 2012 and the decision on the eastern portion of the system was received on November 9, 2012.

PNG operates under cost-of-service regulation and filed its 2013 revenue requirement on November 30, 2012. The BCUC has a review of the regulated returns underway through a Generic Cost of Capital proceeding. A decision on the 2013 return and capital structure is expected in second quarter 2013.

Heritage Gas Limited

Heritage Gas has the exclusive rights to distribute natural gas through its distribution system to all or part of six counties in Nova Scotia, including the Halifax Regional Municipality (HRM). Heritage Gas offers 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.

Potential customers are those with direct access to natural gas service. At the end of 2012, Heritage Gas had approximately 11,800 potential customers with access to its distribution system. Of these potential customers, Heritage Gas had activated approximately 4,300 service lines. Heritage Gas' year-end rate base grew by $20.0 million, or 11 percent in 2012, increasing the year-end rate base to $207.8 million.

Heritage Gas operates under cost-of-service regulation and is expected to file for new rates for its fiscal year of 2015. The application is expected to be made in 2014. Heritage Gas is regulated by the Nova Scotia Utility and Review Board (NSUARB).

In 2012, Heritage Gas began to develop a CNG distribution system which will allow customers not connected through the distribution infrastructure to gain access to natural gas. This CNG business resulted in total capital expenditures of $3.7 million during 2012. Work will continue on this project with total expenditures expected to be approximately $12 million. This CNG project is being developed and operated initially as a non-regulated business.

In Heritage Gas' development stage, the actual regulated revenues billed to customers were less than the approved revenue requirement. Heritage Gas has approval from the NSUARB to accumulate, up to a maximum of $50 million, in a revenue deficiency account (RDA) for this shortfall. The RDA changes based on the difference between the actual revenue billed and the revenue requirement approved by the NSUARB. As the distribution network matures, the actual revenue billed is expected to exceed the revenue requirement, and the RDA will be drawn down. The RDA is a component of Heritage Gas' rate base upon which it earns a return.

For 2012, Heritage Gas' approved regulated ROE was 11 percent (2011 – 13 percent) and debt recovery rate of 7.25 percent (2011 – 8.75 percent) on a prescribed capital structure of 45 percent equity and 55 percent debt.

Inuvik Gas Ltd. & Ikhil Joint Venture

AltaGas has a one-third equity interest in both Inuvik Gas and Ikhil Joint Venture (Ikhil) natural gas reserves, which supply Inuvik Gas with natural gas to be delivered to the town of Inuvik. The Ikhil natural gas reserves have depleted more rapidly than expected. As such, alternative energy sources are being pursued. Inuvik Gas has installed a propane air mixture system to produce synthetic natural gas. Potential long-term energy solutions are being investigated and work continues with the town of Inuvik, the government of Northwest Territories and other parties.

At the end of 2012 Inuvik Gas provided service to 930 residential and commercial customers (2011 – 921 customers).

CONSOLIDATED FINANCIAL REVIEW

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

Years ended December 31 *($ millions)*	**2012**	2011	2010
		(restated)	*(restated)*
Revenue	**1,450.3**	1,270.6	1,222.1
Net revenue [1]	**664.6**	513.1	504.8
Normalized operating income [1]	**234.6**	184.3	157.5
Normalized EBITDA [1]	**336.9**	265.8	240.2
Net income applicable to common shares	**101.8**	82.7	117.0
Normalized net income [1]	**109.5**	90.2	101.4
Total assets	**5,911.9**	3,556.2	2,743.1
Total long-term liabilities	**3,349.5**	1,637.6	1,225.4
Net additions to property, plant and equipment	**1,532.1**	642.6	211.7
Dividends declared [2]	**132.8**	112.2	54.1
Distributions declared [3]	**–**	–	87.0
Cash flows			
Normalized funds from operations [1]	**281.0**	219.0	192.7

($ per share, except shares outstanding)	**2012**	2011	2010
		(restated)	*(restated)*
Normalized EBITDA [1]	**3.55**	3.16	2.95
Net income – basic	**1.07**	0.98	1.43
Net income – diluted	**1.06**	0.97	1.43
Normalized net income [1]	**1.15**	1.07	1.24
Dividends declared [2]	**1.40**	1.34	0.66
Distributions declared [3]	**–**	–	1.08
Cash flows			
Normalized funds from operations [1]	**2.96**	2.61	2.36
Shares outstanding – basic *(millions)*			
During the period [4]	**95.0**	84.0	81.5
End of period	**105.3**	89.2	82.5

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

2 Dividends declared of $0.11 per common share per month from January 1 until October 27, 2011, $0.115 commencing October 27, 2011 and $0.12 per common share per month commencing September 10, 2012.

3 Distributions declared of $0.18 per trust unit and exchangeable unit per month for the first six months of 2010.

4 Weighted average.

FULL YEAR 2012 CONSOLIDATED FINANCIAL REVIEW

Normalized net income for 2012 was $109.5 million, an increase of over 20 percent compared to $90.2 million reported in 2011. On a per share basis, normalized net income increased 7 percent to $1.15 from $1.07 in 2011. The full year results reflect the impact of the new assets added in the last four months of the year including SEMCO, Busch Ranch wind farm, and the Gordondale and Co-stream gas facilities.

Normalized net income in 2012 increased primarily due to the acquisitions of SEMCO and PNG, addition of new power generation assets, higher power volumes hedged at higher prices, lower natural gas costs at gas-fired power generating facilities, the addition of the new and expanded gas processing facilities, higher fee-for-service revenue in the Gas segment, including a customer dispute settlement, and rate base growth at the Nova Scotia and Alberta utilities. These increases were partially offset by lower power prices and frac spread realized, lower volumes processed at some gas processing facilities, lower transmission revenue, lower power generated at Bear Mountain, outages downstream from several of AltaGas' extraction plants, warmer weather in Nova Scotia, lower approved returns at Heritage Gas and higher operating and administrative expenses and amortization due to the addition of new assets. Interest expense and tax expense were also higher in 2012 compared to 2011, mainly due to the new and expanded assets.

Net income applicable to common shares for 2012 is normalized for several non-recurring items, including after-tax transaction costs and foreign exchange losses of $12.9 million for the acquisition of SEMCO, an after-tax mark-to-market gain of $16.6 million, a one-time after-tax charge related to the Sundance force majeure arbitration decision of $8.2 million, a $2.1 million after-tax write-down of assets (2011 – $0.5 million), and $1.1 million of income tax expense, compared to an income tax recovery of $6.8 million in 2011 related to changes in the future tax rate assumption. In 2011 AltaGas also reported a $5.4 million after-tax gain on the sale of a gas plant.

Net income applicable to common shares for 2012 was $101.8 million ($1.07 per share) compared to $82.7 million ($0.98 per share) in 2011.

On a cash flow basis, normalized funds from operations for 2012 increased 28 percent to $281.0 million ($2.96 per share), compared to $219.0 million ($2.61 per share) in 2011. Normalized EBITDA for 2012 was $336.9 million, a 27 percent increase, compared to $265.8 million in 2011.

On a consolidated basis, normalized operating income for 2012 was 27 percent higher at $234.6 million compared to $184.3 million in 2011. Earnings from the operating assets continue to reflect the successful execution of AltaGas' strategy. Normalized operating results were driven by the same factors as described above related to normalized net income except for the impact of higher interest and income taxes.

On a consolidated basis, net revenue for 2012 was $664.6 million compared to $513.1 million in 2011. The increase in net revenue was driven by the same factors impacting normalized net income except for interest and tax expenses, as well as $31.1 million year-over-year positive variance related to mark-to-market on risk management contracts, $11.0 million charge related to the Sundance force majeure arbitration decision, $9.3 million positive variance related to the mark-to-market on the investment in Alterra Power Corp. (Alterra), and $6.2 million gain recorded on sale of a gas plant in 2011.

Operating and administrative expense for 2012 was $323.2 million, compared to $264.9 million in 2011. The increase was primarily due to the addition of SEMCO and PNG and transaction costs related to acquisitions during the period, which were partially offset by lower operating costs at some gas processing facilities due to lower power prices and volumes processed. In 2011, operating and administrative expense included $6.0 million related to planned turnarounds at Younger and Harmattan.

Amortization expense for 2012 was $102.1 million compared to $79.7 million in 2011. The increase was due to the addition of new and expanded facilities, including the acquisitions of SEMCO and PNG, and the write-down of two wind projects under development, partially offset by lower depletion expense at Ikhil. Accretion expense for 2012 was $3.1 million compared to $2.4 million in 2011.

Foreign exchange losses for 2012 were $8.5 million (2011 – $0.4 million), primarily as a result of foreign currency transactions related to the funding of the SEMCO acquisition.

Interest expense for 2012 was $61.2 million compared to $52.7 million in 2011. Interest expense increased due to a higher average debt balance of $1,894.8 million in 2012 compared to $1,032.5 million in 2011. The higher debt was a result of the increased funds necessary to acquire SEMCO and to finance other growth capital. The increase was partially offset by higher capitalized interest of $35.2 million in 2012 (2011 – $11.0 million) and a lower average borrowing rate of 5.1 percent in 2012 (2011 – 6.2 percent).

AltaGas recorded income tax expense of $46.1 million for 2012 compared to $20.3 million in 2011. Income tax expense was higher for 2012 compared to 2011 due to higher unrealized gains on risk management contracts, the addition of SEMCO and PNG, and changes in the future tax rate assumption which resulted in higher income tax expense of $1.1 million in 2012, compared to an income tax recovery of $6.8 million in 2011.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures for 2013 to be $350 to $400 million. Given AltaGas' transformational growth, the Corporation is focused on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets. AltaGas is positioned to deliver growth in earnings and cash flow per share for several years and the Corporation is working to set the stage for continued growth.

AltaGas' committed capital program is fully funded through growing internally-generated cash flow, the dividend reinvestment plan and available bank lines. As at December 31, 2012, the Corporation had approximately $772 million available in its credit facilities.

AltaGas mitigates project cost escalation and schedule risk on its projects under construction through its procurement and contracting strategies. The following is a summary of progress made during 2012 on projects currently under construction and in advanced development:

Northwest Projects

The Northwest Projects consist of three run-of-river hydroelectric projects in northwest British Columbia: the Forrest Kerr Project, McLymont Creek Project and Volcano Creek Project. All three projects are currently in various phases of construction. The 277 MW Northwest Projects are contracted with 60-year fully inflation indexed EPAs with BC Hydro, as well as IBAs with the Tahltan First Nation.

Forrest Kerr Project

Construction of the 195 MW Forrest Kerr Project is progressing well and is ahead of schedule and on budget. The total project is approximately 75 percent complete. Completion of the powerhouse and the in-river work are progressing ahead of schedule. Construction is expected to be completed by the end of 2013, with commissioning to follow based on the availability of the NTL. The plant is expected to be in service in mid-2014.

McLymont Creek and Volcano Creek Projects

All material permits and licences are in place and construction has commenced on both the 66 MW McLymont Creek Project and 16 MW Volcano Creek Project. Construction of the McLymont access road and bridge work is expected to be completed in the first half of 2013. The detailed engineering for McLymont Creek and Volcano Creek projects is underway and will be completed by the end of the first and second quarters of 2013, respectively. The two projects are expected to be in service in late 2015.

JEEP West Central Gas Pipeline

In third quarter 2012, AltaGas acquired a 50 percent interest in Quatro midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby Gas Plant for approximately $20 million. In addition, AltaGas plans to construct a 70-kilometre pipeline (West Central Gas Pipeline) to connect the Gilby Gas Plant and AltaGas' 30 Mmcf/d Sylvan Lake gas plant to AltaGas' deep-cut, turbo expander facility at the Joffre Ethane Extraction Plant (JEEP). Increased volumes processed at the plant are expected to fully utilize JEEP's excess capacity.

The construction of the West Central Gas Pipeline will provide producers in the Glauconite and Duvernay resource plays with increased NGL recovery, improve their recoverable barrels of oil equivalent (BOEs) and increase the value received for their ethane and other NGL products. The West Central Gas Pipeline project is subject to customary conditions. Capital costs and schedule will continue to be refined as the project plan is finalized. The volumes committed to the West Central Gas Pipeline and JEEP are underpinned by long-term fee-for-service contracts.

Non-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These measures provide additional information that management believes is meaningful regarding AltaGas' operational performance, liquidity and capacity to fund dividends, capital expenditures and other investing activities. The specific rationale for and incremental information associated with each non-GAAP measure is discussed below.

References to net revenue, normalized operating income, normalized EBITDA, normalized net income and normalized funds from operations throughout this document have the meanings as set out in this section.

Net Revenue

Years ended December 31 *($ millions)*	**2012**	2011	2010
		(restated)	*(restated)*
Net revenue	**$ 664.6**	$ 513.1	$ 504.8
Add (deduct):			
Income from equity investments	**(66.6)**	(75.3)	(36.5)
Cost of sales	**852.3**	832.8	753.8
Revenue (GAAP financial measure)	**$1,450.3**	$1,270.6	$1,222.1

Management believes that net revenue, which is revenue plus "Income from equity investments" not held-for-trading, less the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of natural gas affect both revenue and cost of sales, and equity investments are part of operating activities for the Corporation.

Normalized Operating Income

Years ended December 31 *($ millions)*	**2012**	2011	2010
		(restated)	*(restated)*
Normalized operating income	**$234.6**	$184.3	$157.5
Add (deduct):			
Unrealized gain (loss) on held-for-trading	**0.2**	(9.1)	(4.3)
Transaction costs related to acquisitions	**(6.8)**	(5.7)	(1.0)
Gain on asset disposition	**–**	6.2	–
Write-down of assets	**(2.9)**	(0.6)	–
Sundance force majeure arbitration decision	**(11.0)**	–	–
Operating income	**214.1**	175.1	152.2
Add (deduct):			
Unrealized gain (loss) on risk management contracts	**22.0**	(9.0)	26.8
Interest expense	**(61.2)**	(52.7)	(48.8)
Foreign exchange loss	**(8.5)**	(0.4)	(0.1)
Income tax expense	**(46.1)**	(20.3)	(9.4)
Net income applicable to non-controlling interests	**(3.5)**	–	–
Preferred share dividends	**(15.0)**	(10.0)	(3.7)
Net income applicable to common shares (GAAP financial measure)	**$101.8**	$ 82.7	$117.0

Operating income is a measure of AltaGas' profitability from its principal operating activities prior to how these activities are financed, how the results are taxed, or the impact of unrealized gains or losses on risk management contracts. The measure is used to assess operating performance since management believes that it is a better indicator of operating performance than net income. Operating income is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, interest expense, foreign exchange loss, income tax expense, net income applicable to non-controlling interests and preferred share dividends.

Normalized operating income represents operating income adjusted for non-operating related expenses such as transaction costs related to acquisitions, gains or losses on sale of assets, mark-to-market gains and losses related to equity investments and non-recurrent events such as write-down of assets.

Normalized EBITDA

Years ended December 31 *($ millions)*	**2012**	2011	2010
		(restated)	*(restated)*
Normalized EBITDA	**$336.9**	$265.8	$240.2
Add (deduct):			
Unrealized gain (loss) on held-for-trading	**0.2**	(9.1)	(4.3)
Transaction costs related to acquisitions	**(6.8)**	(5.7)	(1.0)
Gain on asset disposition	**–**	6.2	–
Sundance force majeure arbitration decision	**(11.0)**	–	–
EBITDA	**319.3**	257.2	234.9
Add (deduct):			
Unrealized gain (loss) on risk management contracts	**22.0**	(9.0)	26.8
Depreciation, depletion and amortization	**(102.1)**	(79.7)	(82.7)
Accretion of asset retirement obligations	**(3.1)**	(2.4)	–
Interest expense	**(61.2)**	(52.7)	(48.8)
Foreign exchange loss	**(8.5)**	(0.4)	(0.1)
Income tax expense	**(46.1)**	(20.3)	(9.4)
Net income applicable to non-controlling interests	**(3.5)**	–	–
Preferred share dividends	**(15.0)**	(10.0)	(3.7)
Net income applicable to common shares (GAAP financial measure)	**$101.8**	$ 82.7	$117.0

EBITDA is a measure of AltaGas' operating profitability without the impact of risk management contracts and prior to how business activities are financed, assets are amortized or earnings are taxed. AltaGas does not speculate on commodity prices, but rather enters into financial instruments to manage risk, and therefore evaluates company performance excluding unrealized gains or losses from risk management contracts. EBITDA is calculated from the Consolidated Statements of Income using net income applicable to common shares adjusted for pre-tax unrealized gains or losses on risk management contracts, depreciation, depletion and amortization, accretion of asset retirement obligations, interest expense, foreign exchange loss, income tax expense, net income applicable to non-controlling interests and preferred share dividends.

Normalized EBITDA represents EBITDA adjusted for non-operating related one-time expenses such as transaction costs related to acquisitions, gains or losses on sale of assets, mark-to-market gains and losses related to equity investments and arbitration decisions.

Normalized Net Income

Years ended December 31 *($ millions)*	**2012**	2011	2010
		(restated)	*(restated)*
Normalized net income	**$109.5**	$90.2	$101.4
Add (deduct):			
Unrealized gain (loss) on risk management contracts	**16.4**	(6.9)	20.1
Unrealized gain (loss) on held-for-trading assets	**0.2**	(8.0)	(3.8)
Transaction and foreign exchange costs related to acquisitions	**(12.9)**	(4.3)	(0.7)
Gain on asset disposition	**–**	5.4	–
Write-down of assets	**(2.1)**	(0.5)	–
Sundance force majeure arbitration decision	**(8.2)**	–	–
Statutory rate change	**(1.1)**	6.8	–
Net Income applicable to common shares (GAAP financial measure)	**$101.8**	$82.7	$117.0

Normalized net income represents net income applicable to common shares adjusted for all mark-to-market accounting and non-operating related one-time expenses, such as transaction costs related to acquisitions including foreign exchange gains or losses, gains or losses on sale of assets and non-recurrent events, such as write-down of assets, arbitration decisions and one-time adjustments to statutory tax rate.

Normalized Funds from Operations

Years ended December 31 *($ millions)*	**2012**	2011	2010
		(restated)	*(restated)*
Normalized funds from operations	**$281.0**	$219.0	$192.7
Add (deduct):			
Transaction costs and foreign exchange loss related to acquisitions	**(15.4)**	(5.7)	(1.0)
Sundance force majeure arbitration decision	**(11.0)**	–	–
Funds from operations	**254.6**	213.3	191.7
Add (deduct):			
Net change in operating assets and liabilities	**(105.9)**	(27.0)	(0.8)
Asset retirement obligations settled	**(2.3)**	(0.9)	(0.5)
Cash from operations (GAAP financial measure)	**$146.4**	$185.4	$190.4

Normalized funds from operations are used to assist management and investors in analyzing financial performance without regard to changes in operating assets and liabilities in the period and non-operating related one-time expenses such as transaction costs related to acquisitions including foreign exchange and arbitration decisions. Funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP.

Funds from operations are calculated from the Consolidated Statements of Cash Flows and are defined as cash from operations before net changes in operating assets and liabilities, expenditures incurred to settle asset retirement obligations and non-operating related expenses.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Operating Income

Years ended December 31 *($ millions)*	**2012**	2011
		(restated)
Gas	**$ 93.6**	$105.2
Power	**76.9**	86.7
Utilities	**80.7**	24.2
Subtotal: Operating Segments	**251.2**	216.1
Corporate [1]	**(37.1)**	(41.0)
	$214.1	$175.1

1 Includes mark-to-market gain/loss on equity investments and transaction costs and excludes mark-to-market gain/loss on risk management contracts.

GAS

OPERATING STATISTICS

Years ended December 31	2012	2011
Extraction and Transmission (E&T)		
Extraction inlet gas processed *(Mmcf/d)* [1]	**889**	883
Extraction ethane volumes *(Bbls/d)* [1]	**25,499**	26,565
Extraction NGL volumes *(Bbls/d)* [1]	**14,593**	14,513
Total extraction volumes *(Bbls/d)* [1]	**40,092**	41,078
Frac spread – realized *($/Bbl)* [1,2]	**30.83**	33.67
Frac spread – average spot price *($/Bbl)* [1,3]	**29.22**	42.88
Field Gathering and Processing (FG&P)		
Processing throughput *(gross Mmcf/d)* [1]	**372**	391
Energy Services		
Average volumes transacted *(GJ/d)* [1,4]	**356,526**	369,603

1 *Average for the period.*

2 *Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac exposed volumes plus the settlement value of frac hedges settled in the period less shrinkage gas and extraction premiums, divided by the total frac exposed volumes produced during the period.*

3 *Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less shrinkage gas and extraction premiums, divided by the respective frac exposed volumes for the period.*

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

In 2012, average ethane volumes decreased by 1,066 Bbls/d and NGL volumes increased by 80 Bbls/d, compared to 2011. Ethane volumes were lower in 2012 largely due to outages downstream from several of AltaGas' extraction plants and reduced ethane recovery during the commissioning phase of the Co-stream Project. NGL volumes were slightly higher in 2012 compared to 2011 as a result of the planned turnarounds in 2011.

FG&P throughput in 2012 averaged 372 Mmcf/d compared to 391 Mmcf/d in 2011. During 2012, volumes at certain gas processing facilities grew by approximately 52 Mmcf/d compared to 2011. However, overall volumes processed were down due to declines and shut-ins led by producers in response to low natural gas prices and outages. These decreases were partially offset by the expansion of the Blair Creek facility, the addition of the Gilby Gas Plant effective July 1, 2012, the acquisition of the Marlboro gas plant in 2011 and the commissioning of the new Gordondale facility.

In December 2012, AltaGas completed commissioning and began commercial operation of both the Co-stream and Gordondale facilities.

Financial Results 2012

The Gas segment recorded operating income of $93.6 million in 2012 compared to $105.2 million in 2011. Operating income decreased primarily due to lower realized frac spread, lower transmission revenue, lower gathering and processing volumes, higher amortization and accretion expense, and lower contributions from energy services. These decreases were partially offset by the addition of new and expanded gas processing facilities, a settlement of a customer dispute, and lower operating and administrative costs. For 2011 results included the sale of the Groundbirch facility, settlement of a take-or-pay contract and the impact of planned turnarounds.

For the year-ended December 31, 2012, AltaGas hedged approximately 82 percent of frac exposed production at an average price of approximately $35/Bbl before deducting extraction premiums. For the year-ended December 31, 2011, AltaGas hedged approximately 70 percent of frac exposed production at an average price of $28/Bbl before deducting extraction premiums. The average indicative spot NGL frac spread, before deducting extraction premiums, in 2012 was approximately $30/Bbl compared to approximately $43/Bbl in 2011.

Net revenue in the Gas segment for the year ended December 31, 2012 was $322.2 million, compared to $337.9 million in 2011. Net revenue decreased due to lower realized frac margins, lower daily contract quantity on the Suffield transmission system, an outage upstream of the Porcupine Hills Pipeline, lower contributions from gas services and lower gas processing volumes. Net revenue also decreased due to a one-time gain on sale of the Groundbirch facility. These decreases were partially offset by lost revenue in 2011 due to planned turnarounds, the addition of new and expanded gas processing facilities and higher realized storage margins.

Operating and administrative expense for 2012 was $168.5 million compared to $175.9 million in 2011. Operating costs were lower due to the impact of planned turnarounds in 2011, lower power costs and lower volumes processed at certain gas processing facilities, offset by a one-time liability adjustment recorded in 2011.

Amortization expense in 2012 was $57.2 million compared to $54.4 million in 2011. Accretion expense in 2012 was $3.0 million compared to $2.4 million in 2011. The increase in amortization and accretion expense was as a result of expansions in the Gas segment in 2012.

POWER
OPERATING STATISTICS

Years ended December 31	2012	2011
Volume of power sold *(GWh)*	**3,317**	3,003
Average price realized on the sale of power *($/MWh)*	**69.42**	75.94
Alberta Power Pool average spot price *($/MWh)*	**64.32**	76.22

In 2012, volume of power sold increased by 314 GWh compared to 2011. Volumes sold in 2012 comprised of 2,875 GWh conventional power generation and 442 GWh renewable power generation, compared to 2,821 GWh conventional power generation and 182 GWh wind generation in 2011.

Financial Results 2012

The Power segment reported operating income of $76.9 million in 2012 compared to $86.7 million in 2011. Operating income decreased as a result of lower realized power prices, the charge related to the Sundance force majeure arbitration decision, lower generation at Bear Mountain and the write-down of two wind projects under development. These decreases were partially offset by a higher percentage of power hedged, the addition of new power assets, higher generation at the gas-fired peaking plants and higher contribution from the C&I power sales.

For the year ended December 31, 2012, AltaGas was 70 percent hedged in Alberta at an average price of $67/MWh. In 2011, AltaGas was 62 percent hedged at an average price of $70/MWh.

Net revenue for 2012 was $109.0 million compared to $113.6 million for 2011. Net revenue decreased due to lower realized power prices, the charge related to the Sundance force majeure arbitration decision, and lower power generated at Bear Mountain. These decreases were partially offset by the addition of new biomass power assets, the addition of Cogeneration II at Harmattan, lower natural gas costs at all gas-fired generating facilities and the addition of Busch Ranch.

Operating and administrative expense was $18.1 million for 2012 compared to $16.7 million for 2011. The increase was primarily due to operating and administrative costs related to new power assets and increased business development activities.

Amortization expense was $14.0 million for 2012 compared to $10.3 million for 2011. Amortization increased in 2012 primarily due to write-down of two wind projects under development and the addition of new assets. In addition, the Crowsnest Pass project was disposed in fourth quarter 2012 resulting in a loss of $0.1 million.

UTILITIES

OPERATING STATISTICS

Years ended December 31	2012	2011
Canadian utilities		
Natural gas deliveries – end-use *(PJ)* [1]	**28.5**	21.8
Natural gas deliveries – transportation *(PJ)* [1]	**6.8**	4.6
U.S. utilities [2]		
Natural gas deliveries – end-use *(Bcf)* [1]	**26.0**	–
Natural gas deliveries – transportation *(Bcf)* [1]	**13.9**	–
Service sites [3]	**547,977**	115,011
Degree day variance from normal – AUI *(%)* [4]	**(0.7)**	–
Degree day variance from normal – Heritage Gas *(%)* [4]	**(9.1)**	(12.7)
Degree day variance from normal – SEMCO Gas *(%)* [2,5]	**(0.3)**	–
Degree day variance from normal – ENSTAR *(%)* [2,5]	**9.6**	–

1 *Petajoule (PJ) is one million gigajoules. Bcf is one billion cubic feet.*

2 *Results for U.S. utilities are from August 30, 2012.*

3 *Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and U.S. utilities, including transportation and non-regulated business lines.*

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

5 *A degree day for U.S. utilities is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior fifteen years for SEMCO Gas and during the prior ten years for ENSTAR.*

REGULATORY METRICS

Years ended December 31	2012	2011
Approved return on equity *(%)*		
Canadian utilities *(average)*	**10.0**	11.1
U.S. utilities *(average)*	**11.3**	–
Approved return on debt *(%)*		
Canadian utilities *(average)*	**6.5**	7.2
U.S. utilities *(average)*	**5.6**	–
Rate base *($ millions)* [1]		
Canadian utilities	**569.6**	529.2
U.S. utilities [2,3]	**757.4**	–

1 *Rate base is indicative of the earning potential of each utility over time. Approved revenue requirement for each utility is typically based on the rate base as approved by the regulator for the respective rate application, which may be different from that indicated above.*

2 *In U.S. dollars.*

3 *Reflects AltaGas' 65 percent interest in CINGSA.*

2012 Financial Results

Since the acquisition on August 30, 2012, SEMCO has met expectations, adding $47 million in EBITDA in 2012.

The Utilities segment reported operating income of $80.7 million in 2012, a significant increase compared to $24.2 million in 2011. Operating income increased mainly due to the acquisitions of SEMCO and PNG, which contributed $50.9 million to operating income in the year, rate base growth of 11 percent at both AUI and Heritage Gas, lower operating costs and depletion expense at Ikhil. These increases were partially offset by warmer than normal weather experienced in Nova Scotia and lower approved returns at the Nova Scotia utility.

Net revenue in 2012 was $212.7 million compared to $81.9 million in 2011. Net revenue increased due to the acquisition of SEMCO on August 30, 2012 and PNG in mid-December 2011, and rate base growth at AUI and Heritage Gas. These increases were partially offset by warmer weather experienced in Nova Scotia, lower approved returns at Heritage Gas, lower volume of natural gas sold at Ikhil and lower recoverable costs at AUI as a result of the AUC decision on its 2011/2012 GRA.

Operating and administrative expense was $104.5 million in 2012 compared to $46.9 million in 2011. The increase in operating costs was mainly due to the addition of SEMCO and PNG.

Amortization expense was $27.5 million in 2012 compared to $10.8 million in 2011. The increase in amortization expense was mainly due to the addition of SEMCO and PNG. These increases were partially offset by lower amortization at AUI as a result of the AUC decision on its 2011/2012 GRA and lower depletion expense at Ikhil.

CORPORATE

Description of Corporate Assets

The corporate reporting segment (Corporate 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 is reported and monitored in the Corporate segment.

2012 Financial Results

The operating loss excluding the impact of mark-to-market accounting on risk management contracts in 2012 was $37.1 million compared to $41.0 million in 2011. The decrease in loss was due to $0.2 million of unrealized pre-tax gain on an equity investment in 2012 compared to an unrealized pre-tax loss of $9.1 million in 2011. This was partially offset by higher general and administrative costs and foreign exchange losses associated with transaction costs.

Net revenue was $22.6 million in 2012 compared to net revenue in a deficit position of $18.4 million in 2011. The increase in net revenue was due to unrealized pre-tax gains on risk management contracts of $22.1 million in 2012 compared to unrealized pre-tax losses of $9.0 million in 2011, and an unrealized pre-tax gain of $0.2 million on an equity investment compared to an unrealized pre-tax loss of $9.1 million in 2011.

Operating and administrative expense was $34.2 million in 2012 compared to $27.4 million in 2011. The increase in general and administrative expense is primarily due to transaction costs related to acquisitions.

Amortization expense was $3.5 million in 2012 compared to $4.2 million in 2011. Amortization expense was lower in 2012 compared to 2011 due to reallocation of certain capital assets to other operating segments during third quarter 2011.

INVESTED CAPITAL

For the year ended December 31, 2012, AltaGas increased property, plant and equipment, intangible assets, long-term investments and other assets by $1,624.3 million compared to $747.0 million for 2011.

For the year ended December 31, 2012, AltaGas disposed property, plant and equipment of $18.2 million and terminated a capital lease of $13.9 million. Subsequent to the lease termination, AltaGas purchased the previously leased assets. For the year ended December 31, 2011, AltaGas disposed property, plants and equipment of $30.9 million.

The net invested capital was $1,592.2 million for the year ended December 31, 2012 compared to $715.8 million for 2011.

Invested Capital – Investment Type

Year ended December 31, 2012 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	**$362.6**	**$316.8**	**$882.9**	**$ 0.8**	**$1,563.1**
Intangible assets	**2.4**	**–**	**17.9**	**1.4**	**21.7**
Long-term investments and other assets	**0.2**	**36.4**	**2.6**	**0.3**	**39.5**
	365.2	**353.2**	**903.4**	**2.5**	**1,624.3**
Disposals:					
Property, plant and equipment	**(0.5)**	**(31.6)**	**–**	**–**	**(32.1)**
Long-term investments and other assets	**–**	**–**	**–**	**–**	**–**
Net Invested capital	**$364.7**	**$321.6**	**$903.4**	**$ 2.5**	**$1,592.2**

Invested Capital – Investment Type

Year ended December 31, 2011 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Property, plant and equipment	$282.7	$163.0	$211.6	$ 7.0	$ 664.3
Intangible assets	6.5	91.3	2.7	0.1	100.6
Long-term investments and other assets	(0.3)	(0.4)	0.3	(17.5)	(17.9)
	288.9	253.9	214.6	(10.4)	747.0
Disposals:					
Property, plant and equipment	(28.2)	(0.3)	(2.4)	–	(30.9)
Long-term investments and other assets	–	–	–	(0.3)	(0.3)
Net Invested capital	$260.7	$253.6	$212.2	$(10.7)	$ 715.8

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

Growth capital expenditures of $1,609.6 million was reported in 2012 (2011 – $729.6 million).

In the Gas segment, growth capital comprised of $179.1 million for construction of the Gordondale, $86.8 million for the Co-stream Project, $53.1 million for the Blair Creek facility expansion, $14.7 million for Quatro asset purchase and $19.5 million for various other Gas related projects.

Within the Power segment, growth capital projects included $248.4 million for the Forrest Kerr Project, $35.0 million for the acquisition of DEI, $25.6 million for Busch Ranch partially offset by the U.S. government grant of $7.4 million, $12.1 million for the buyout of Maxim capital lease, $11.4 million for the Crowsnest Pass project (eventually disposed in November 2012 for total costs incurred to date of $17.7 million), $11.0 million for the McLymont Creek Project, $9.6 million for the addition of Cogeneration II at Harmattan, $3.1 million for gas-fired peakers at Gordondale and $2.3 million for the Volcano Creek Project.

Utilities segment reported growth capital of $847.1 million from the SEMCO acquisition and $56.3 million from other rate-regulated assets.

The Corporate segment reported an increase in capital of $0.3 million related to the change in fair value of AltaGas' investment in Alterra and $1.6 million for other projects.

Maintenance and administrative capital expenditures for 2012 were $11.5 million and $3.2 million, respectively (2011 – $5.4 million and $12.0 million, respectively).

Invested Capital – Use

Year ended December 31, 2012 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	**$ 9.4**	**$ 2.1**	**–**	**–**	**$ 11.5**
Growth	**353.2**	**351.1**	**903.4**	**1.9**	**1,609.6**
Administrative	**2.6**	**–**	**–**	**0.6**	**3.2**
Invested capital	**$365.2**	**$353.2**	**$903.4**	**$ 2.5**	**$1,624.3**

Invested Capital – Use

Year ended December 31, 2011 *($ millions)*	Gas	Power	Utilities	Corporate	Total
Invested capital:					
Maintenance	$ 3.6	$ 1.8	–	–	$ 5.4
Growth	280.8	252.1	214.3	(17.6)	729.6
Administrative	4.4	–	0.3	7.3	12.0
Invested capital	$288.8	$253.9	$214.6	$(10.3)	$ 747.0

RISK MANAGEMENT

Market Risk

The Corporation is exposed to market risk and potential loss from changes in the value of financial instruments. AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices, interest rates and foreign exchange rates. During 2012, the Corporation had positions in the following types of derivatives, which are also disclosed in Note 16 of the Consolidated Financial Statements:

Commodity Forward Contracts:

The Corporation executes gas, power and other commodity forward contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. In a forward contract, one party agrees to deliver a specified amount of an underlying asset to the other party at a future date at a specified price. The energy services division transacts primarily on this basis. Prior to spring of 2011, PNG hedged exposures to fluctuations in natural gas prices through the use of derivative financial instruments, in accordance with its annual gas contracting and gas supply price risk management plan. These instruments expired in October 2012. In accordance with revised price risk management procedures approved by the BCUC, PNG has not entered into any new hedging arrangements since that time.

Commodity Swap Contracts:

Power hedges:

AltaGas executes fixed for floating power price swaps to manage its power asset portfolio. A fixed for floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power segment results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices range from $0.00/MWh to $1,000.00/MWh in 2012 and $0.00/MWh to $999.99/MWh in 2011. The average Alberta spot price was $64.32/MWh in 2012 (2011 – $76.22/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 $69.42/MWh in 2012 (2011 – $75.94/MWh). For 2013, AltaGas has hedged approximately 50 percent of power at an average price of $65/MWh.

NGL frac spread hedges:

The Corporation executes fixed for floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. During 2012, the Corporation had NGL frac spread hedges for an average of 4,475 Bbls/d at an average price of approximately $35/Bbl before deducting extraction premiums. The average indicative spot NGL frac spread before deducting extraction premiums for 2012 was an estimated $29/Bbl (2011 – $43/Bbl). The average NGL frac spread realized by AltaGas in 2012 was $31/Bbl after deducting extraction premiums (2011 – $34/Bbl which was impacted by the 2011 Younger turnaround). For the entire 2013 period, 2,000 Bbls/d of propane-plus volumes have been hedged at approximately $35/Bbl. An additional 1,000 Bbls/d of propane has been hedged for the first six months of 2013.

Interest Rate Forward Contracts:

From time to time, the Corporation enters into interest rate swaps where cash flows of a fixed rate are exchanged for those of a floating rate, or vice versa. At December 31, 2012, the Corporation had no interest rate swaps outstanding. At December 31, 2012, the Corporation had fixed the interest rate on 73.5 percent of its debt including MTNs (December 31, 2011 – 96 percent).

Foreign Exchange Forward Contracts:

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts whereby a fixed rate is locked in against a floating rate and option agreements whereby an option to transact foreign currency at a future date is purchased or sold. In third quarter 2012, AltaGas entered into a back-to-back swap transaction for a notional amount of US$192.5 million which was settled on August 27, 2012.

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 interest rate and foreign exchange derivatives used quoted market rates.

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

BUSINESS RISKS

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

Risks	Strategies and Organizational Capability to Mitigate Risks
Long-term natural gas volume declines	• Contract provisions underpin capital commitments • Long-term contracts 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 geographic 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
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 hydrology studies to support investment decisions
Operational	• Acquire large working interests to control and optimize operations and maximize efficiencies • Contractual provisions often provide for recovery of operating costs • Centralized procurement strategy to reduce costs • Maintain control over operational decisions, operating cost and capital expenditures by operating facilities • Maintain written standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs • Long-term maintenance contract with wind turbine manufacturer (Enercon) • Fixed price operating and maintenance contracts with equipment manufacturers • 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
Commodity price	• 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 • Disciplined hedging strategy with hedge targets approved by the Board of Directors • Monitor hedge transactions through Risk Management Committee • AltaGas' policy dealing with commodity risk (Commodity Risk Policy) prohibits transactions for speculative purposes • 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 • Employ strong systems and processes for monitoring and reporting compliance with the Commodity Risk Policy • In-depth knowledge and experience of transportation systems, natural gas, NGL and power markets • Hedge power costs • Avoid commodity price exposure on electricity energy sources • 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 natural gas-fired generating capacity • Execute long-term inflation adjusted electricity purchase arrangements with power buyers

Risks	Strategies and Organizational Capability to Mitigate Risks
Counterparty	• Strong credit policies and procedures • Continuous review of counterparty credit worthiness • 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 terms included in gas processing contracts
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
Weather	• Anticipated volumes are determined based on the 20-year rolling average for weather for the Canadian utilities and 15 years for SEMCO Gas and 10 years for ENSTAR • PNG has a weather normalization account for residential and small commercial customers which means variations in weather do not materially affect PNG's earnings
Regulatory and First Nations	• Regulatory and commercial personnel monitor and react to regulatory issues • Proactive regulatory and government relations group, with strong working relationships with First Nations and their stakeholders, and the respective regulators and their staff • Build risk mitigation into contracts where possible • Skilled regulatory department retained at AUI, PNG, Heritage Gas, SEMCO Gas, ENSTAR and AltaGas head office • Use of expert third parties when needed
Environment and safety	• Strong safety and environmental management systems, which AltaGas continually strives to improve • Focus on mitigating the impact of the SGER
Labour relations	• Access to a strong labour market to attract qualified talent to the organization • Positive employee relations to retain existing talent and maintain strong relations with unions

LIQUIDITY

AltaGas does not expect any currently known trend or uncertainty to affect its ability to access its historical sources of funding. During the year ended December 31, 2012, there were no actual or anticipated default/arrears on dividend payments, lease payments, interest or principal payments on debt or debt covenants.

Cash Flows

Years ended December 31 *($ millions)*	**2012**	2011
		(restated)
Cash from operations	**$146.4**	$185.4
Investing activities	**(1,624.5)**	(564.4)
Financing activities	**1,487.1**	380.8
Change in cash	**$ 9.0**	$ 1.8

Cash from Operations

Cash from operations reported on the Consolidated Statements of Cash Flows was $146.4 million in 2012 compared to $185.4 million in 2011. The decrease in cash from operations was primarily a result of lower net change in operating assets and liabilities and lower funds from operations in the year as compared to 2011, due to the cash used for transaction costs and foreign exchange loss related to the SEMCO acquisition, partially offset by higher net income.

Working Capital

As at December 31 *($ millions except current ratio)*	**2012**	2011
		(restated)
Current assets	**$591.4**	$351.7
Current liabilities	**562.7**	557.9
Working capital	**28.7**	(206.2)
Current ratio	**1.05**	0.63

Working capital was $28.7 million as at December 31, 2012, compared to a deficit position of $206.2 million as at December 31, 2011. The working capital ratio was 1.05 at the end of 2012 compared to 0.63 at the end of 2011. The working capital ratio increased due to an increase in accounts receivable and inventory, and a decrease in current portion of long-term debt and risk management liabilities. This was partially offset by an increase in accounts payable, short-term debt and customer deposits, and a decrease in risk management assets.

Investing Activities

Cash used for investing activities in 2012 was $1,624.5 million compared to $564.4 million in 2011. Investing activities in 2012 were primarily comprised of $806.0 million related to the SEMCO and DEI acquisitions, $768.7 million of property, plant and equipment expenditures, and $52.8 million on acquisition of intangible assets. Investing activities in 2011 were comprised of $400.2 million of property, plant and equipment expenditures, $138.0 million related to the PNG acquisition and $33.0 million on acquisition of intangible assets.

Financing Activities

Cash received from financing activities was $1,487.1 million in 2012 compared to $380.8 million in 2011. Financing activities in 2012 were primarily comprised of $1,054.0 million from the issuance of MTNs and other long-term debt, repayment of long-term debt of $105.1 million, net proceeds from issuance of common shares of $435.6 million, and net proceeds from the issuance of preferred shares of $199.0 million, compared to the issuance of $397.7 million of long-term debt and net proceeds from issuance of common shares of $179.8 million in 2011. Dividends paid to common and preferred shareholders in 2012 were $145.3 million compared to $121.9 million in 2011.

CAPITAL RESOURCES

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

The use of debt or equity funding is based on AltaGas' capital structure which is determined by considering the norms and risks associated with each of its business segments.

As at December 31, 2012, AltaGas had total debt outstanding of $2,702.3 million, up from $1,337.1 million at December 31, 2011. As at December 31, 2012, AltaGas had $1,625.0 million in MTNs outstanding, PNG debenture notes of $64.2 million, SEMCO long-term debt of $303.4 million and had access to prime loans, base rate loans, LIBOR loans, bankers' acceptances, and letters of credit through bank credit facilities of $1,620.0 million. As at December 31, 2012, AltaGas' current portion of long-term debt was $9.3 million (December 31, 2011 – $106.0 million).

AltaGas' earnings interest coverage for the rolling 12 months ended December 31, 2012 was 2.36 times.

AltaGas' debt-to-total capitalization ratio as at December 31, 2012 was 57.4 percent (December 31, 2011 – 49.5 percent).

	December 31, 2012	December 31, 2011 *(restated)*
Debt		
Short-term debt	**$ 66,938**	$ 16,824
Current portion of long-term debt	**9,302**	105,962
Long-term debt	**2,626,086**	1,214,298
Less cash and cash equivalent	**(11,827)**	(2,875)
Net debt	**2,690,499**	1,334,209
Shareholders' equity	**1,959,791**	1,355,362
Non-controlling interests	**40,006**	5,426
Total capitalization	**$4,690,296**	$2,694,997
Debt-to-total capitalization ratio *(%)*	**57.4**	49.5

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas has been in compliance with these covenants each quarter since the establishment of the facilities. The following table summarizes the Corporation's debt covenants for all credit facilities as at December 31, 2012:

Ratios	Debt covenant requirements
Debt-to-capitalization	For two full quarters post SEMCO acquisition – not greater than 65 percent
	After two full quarters post SEMCO acquisition – not greater than 60 percent
EBITDA-to-interest expense	not less than 2.5x
EBITDA-to-interest expense (SEMCO)	not less than 2.25x
Debt-to-capitalization (SEMCO)	not greater than 60 percent
Debt-to-capitalization (Utility Group)	not greater than 67.5 percent
Debt-to-capitalization (PNG)	not greater than 65 percent

On December 7, 2011, a new $2 billion base shelf prospectus valid for 25 months was filed. The purpose of the shelf is to facilitate timely execution of future debt and/or equity issuances by disclosing standardized information required for each capital issuance. As at December 31, 2012, $1.25 billion remains available on the base shelf prospectus.

On February 22, 2012, AltaGas closed approximately $403.5 million in gross proceeds held in trust in connection with a subscription receipts offering for total consideration of 13,915,000 common shares. The subscription receipts were released from escrow on August 30, 2012 and each receipt was automatically exchanged, for one common share of AltaGas and a dividend equivalent payment of $0.69 per common share in respect of the dividends declared by AltaGas since the initial deal close.

On April 13, 2012, AltaGas issued $200 million of senior unsecured MTNs. The notes carry a coupon rate of 4.07 percent and mature on June 1, 2020.

On May 25, 2012, PNG's $25 million bank operating facility was amended and extended with a new maturity date of November 22, 2013.

On June 6, 2012, AltaGas issued 8,000,000 five-year rate reset Series C Preferred Shares, at a price of US$25 per Series C Preferred Share, for aggregate gross proceeds of US$200 million.

On August 30, 2012, SEMCO entered into an agreement for a new US$100 million unsecured credit facility which is available for working capital purposes and expires on August 30, 2014.

On September 28, 2012, AltaGas issued $350 million of senior unsecured MTNs. On April 13, 2012, AltaGas issued $200 million of senior unsecured MTNs. The net proceeds from these offerings were used to repay outstanding indebtedness under its credit facilities, as well as for general corporate purposes.

On September 28, 2012, AltaGas extended its US$300 million unsecured credit facility with three Canadian chartered banks. The credit facility's term was extended with a new maturity date of September 2, 2014.

As at December 31, 2012, the Corporation had approximately $772 million of available credit facilities and $11.8 million in cash and cash equivalents.

Credit facilities

($ millions)	Borrowing capacity	**Drawn at December 31, 2012**	Drawn at December 31, 2011
Demand operating facilities	$ 70.0	**$ 6.1**	$ 3.4
Extendible revolving letter of credit facility	75.0	**50.0**	67.7
PNG operating facility	25.0	**15.4**	13.9
PNG term revolver	35.0	**30.0**	20.0
Bilateral letter of credit facility	125.0	**89.8**	124.3
AltaGas Ltd. revolving credit facility [1,2]	600.0	**227.3**	8.0
Utility Group revolving credit facility	200.0	**131.3**	30.4
USD unsecured credit facility [1,3]	300.0	**170.0**	–
SEMCO Energy USD unsecured credit facility [1,3]	100.0	**50.2**	–
CINGSA USD secured construction and term loan facility [1,3]	90.0	**77.5**	–
	$1,620.0	**$847.6**	$267.7

1 Borrowing capacity assumed at par.

2 Drawn in U.S. dollars converted at December month-end rate (1 U.S. Dollar = 0.9949 Canadian Dollar).

3 Drawn assumed at par.

CONTRACTUAL OBLIGATIONS

December 31, 2012	Payments Due by Period				
($ millions)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt	$2,634.9	$ 9.3	$620.4	$741.7	$1,263.5
Capital leases	0.4	–	–	–	0.4
Operating leases	42.1	18.6	13.8	9.1	0.6
Purchase obligations	573.8	182.2	213.7	106.0	71.9
Capital project commitments	169.0	131.2	37.8	–	–
Total contractual obligations	$3,420.2	$341.3	$885.7	$856.8	$1,336.4

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

Capital project commitments are related to the construction costs of the Northwest Projects and Gas projects. Amounts are estimates and are subject to variability depending on actual construction costs.

RELATED PARTIES

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

RATING AGENCIES

On February 28, 2013, Standard & Poor's (S&P) maintained the BBB and P-3 High(H) ratings for AltaGas.

On September 24, 2012, DBRS Limited (DBRS) reaffirmed the BBB and Pfd-3 ratings for AltaGas.

On May 31, 2012, DBRS commenced rating of the Series C Preferred Shares with a rating of Pfd-3.

On May 30, 2012, S&P commenced rating of the Series C Preferred Shares with a rating of P-3(H).

On October 31, 2011, DBRS reaffirmed the BBB and Pfd-3 ratings for AltaGas in light of the PNG acquisition.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. The capacity for the payment of financial obligations is considered acceptable, but the entity may be vulnerable to future events which reduce the strength of the entity and its rated securities. "High" or "low" grades are used to indicate the relative standing within a particular rating category. 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.

According to the S&P rating system, an obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. 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

As at December 31, 2012, AltaGas had 105.3 million common shares, 8.0 million series A preferred shares and 8.0 million series C USD preferred shares outstanding with a combined market capitalization of $3.9 billion based on a closing trading price on December 31, 2012 of $33.57 per common share, $25.98 per series A preferred share and $25.26 per series C USD preferred share. As at December 31, 2012, there were 5.8 million options outstanding and 2.7 million options exercisable under the terms of the share option plan.

DIVIDENDS/DISTRIBUTIONS

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

On September 10, 2012, the Board of Directors approved an increase in the monthly dividend to $0.12 per common share from $0.115 per common share effective with the September dividend.

On October 27, 2011, the Board of Directors approved an increase in the monthly dividend to $0.115 per common share from $0.11 per common share effective with the November dividend.

The following table summarizes AltaGas' dividend declaration history:

Dividends/Distributions

Years ended December 31 *($ per common share)*	**2012**	2011	2010 [1]
First quarter	**$ 0.345**	$ 0.33	$ 0.54
Second quarter	**0.345**	0.33	0.54
Third quarter	**0.35**	0.33	0.33
Fourth quarter	**0.36**	0.34	0.33
Total	**$ 1.40**	$ 1.33	$ 1.74

1 *As of July 1, 2010, after AltaGas' conversion to a corporation, monthly dividends are declared to its common shareholders*

Series A Preferred Share Dividends

Years ended December 31 *($ per preferred share)*	**2012**	2011	2010
First quarter	**$0.3125**	$0.3125	–
Second quarter	**0.3125**	0.3125	–
Third quarter	**0.3125**	0.3125	–
Fourth quarter	**0.3125**	0.3125	0.4589
Total	**$ 1.25**	$ 1.25	$0.4589

Series C Preferred Share Dividends

Years ended December 31 *(US$ per preferred share)*	**2012**	2011	2010
Third quarter	**$0.3473**	–	–
Fourth quarter	**0.2750**	–	–
Total	**$0.6223**	–	–

SUBSEQUENT EVENT

On January 28, 2013, AltaGas announced that the Corporation has signed an agreement with Idemitsu to form AltaGas Idemitsu LP. AltaGas Idemitsu LP plans to pursue opportunities involving exports of LPG and LNG from Canada to Asia. AltaGas and Idemitsu will each own 50 percent interest in AltaGas Idemitsu LP.

CHANGES IN ACCOUNTING POLICIES

ADOPTION OF UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

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

On September 10, 2010, the AcSB amended the introduction to Part I of the CICA Handbook Accounting to permit, but not to require qualifying entities with Rate-Regulated Activities (RRA) to adopt IFRS for the first time no later than interim and annual financial statements relating to annual periods beginning on or after January 1, 2012, thereby providing a one-year deferral. The Canadian Securities Administrators provide for a similar one-year deferral pursuant to National Instrument 52-107, Acceptable Accounting Principles and Auditing Standards (NI 52-107).

In light of discussions of the IASB's future agenda, in September 2012 the AcSB amended the introduction to Part I of the Handbook extending the deferral of the mandatory IFRS changeover date for entities with qualifying rate-regulated activities by one-year to January 1, 2014.

AltaGas is a qualified entity for the deferral period permitted by AcSB and NI 52-107. AltaGas has elected to use the deferral offered by the AcSB and NI 52-107, given the uncertainty with respect to the application of IFRS to the RRA. AltaGas reassessed the accounting policy choices available and determined that the most appropriate decision for AltaGas' business activities is the use of US GAAP effective January 1, 2012.

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

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 financial instruments, depreciation, depletion and amortization expense, asset retirement obligations and other environmental costs, asset impairment assessment, income taxes, pension plans and post-retirement benefits, and regulatory assets and liabilities.

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 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.

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 an 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 these derivative instruments to market 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.

Depreciation, Depletion and 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. For regulated entities amortization rates are generally prescribed by the applicable regulatory authority.

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 uncertainty related to assumptions about reserve quantities; and
- Changes in assumptions could result in material adjustments 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 (estimated between 2016 and 2164), 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 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 Corporation 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 and the Internal Revenue Code (U.S.) for the purposes of determining the amount of income that will be subject to tax in the United States. The determination of AltaGas' and its subsidiaries' provision for income taxes requires the application of these complex rules.

Substantial deferred income tax assets and liabilities are recognized in the Consolidated Financial Statements. The recognition of deferred tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. The amount of the deferred 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 14 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 20 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.

Regulatory Assets and Liabilities

The regulated Utilities businesses in Canada are natural gas distribution utilities and are comprised of AUI in Alberta, PNG in British Columbia and Heritage Gas in Nova Scotia. AltaGas also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. On August 30, 2012, AltaGas acquired all of the issued and outstanding shares of SEMCO. SEMCO is the sole shareholder of SEMCO Energy, a rate-regulated utility company headquartered in Port Huron, Michigan. In the United States, indirectly through SEMCO, AltaGas owns and operates ENSTAR and SEMCO Gas, natural gas distribution utilities located in Alaska and Michigan, respectively. SEMCO indirectly also holds a 65 percent interest in CINGSA, a regulated natural gas storage utility and owns a non-controlling interest in a natural gas storage facility in Michigan.

SEMCO Energy, AUI, Heritage Gas, PNG and Inuvik Gas engage in the delivery and sale of natural gas and are regulated by the MPSC and RCA, AUC, NSUARB, BCUC and the Northwest Territories Public Utilities Board (NWTPUB), respectively.

The MPSC, RCA, AUC, NSUARB and BCUC exercise statutory authority over matters such as tariffs, rates, construction, operations, financing, returns and certain contracts with customers. In order to recognize the economic effects of the actions and decisions of the MPSC, RCA, AUC, NSUARB and BCUC, the timing of recognition of certain assets, liabilities, revenues and expenses as a result of regulation may differ from that otherwise expected using US GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to 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 expected 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.

DISCLOSURE CONTROLS AND PROCEDURES (DC&P) AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

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

The Chief Executive Officer and the Chief Financial Officer have designed, with the assistance of AltaGas employees:

- DCP to provide reasonable assurance that material information relating to AltaGas' business is made known to them particularly during the period in which AltaGas' annual filings are being prepared and information required to be disclosed by AltaGas in its annual filings, interim filings or other reports filed or submitted under securities legislation is processed, summarized and reported within the time periods specified in securities legislation; and
- ICFR to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP.

The ICFR have been designed based on the framework established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR and concluded that AltaGas' DCP and ICFR were effective at December 31, 2012. All internal control systems, regardless of how well designed, have inherent limitations. As a result, even those systems determined to be effective can provide only reasonable assurance.

During 2012, there were no changes made to AltaGas' ICFR that materially affected, or are reasonably likely to materially affect, its ICFR.

FOURTH QUARTER HIGHLIGHTS

Operating Income

	Three Months Ended December 31		Year ended December 31	
($ millions)	**2012**	2011	2012	2011
Gas	**$26.3**	$31.4	$ 93.6	$105.2
Power	**14.1**	23.1	76.9	86.7
Utilities	**50.4**	4.7	80.7	24.2
Sub-total: Operating Segments	**90.8**	59.2	251.2	216.1
Corporate	**(9.1)**	(10.1)	(37.1)	(41.0)
	$81.7	$49.1	$214.1	$175.1

Fourth quarter 2012 was the first full quarter for AltaGas' largest acquisition ever and also the quarter in which two significant new gas processing assets were brought into service. The SEMCO acquisition met expectations, adding $42 million in EBITDA. The Gordondale and Co-stream facilities began commercial service in December. Both projects are ramping up volumes. The Co-stream facility is underpinned by a cost-of-service contract and reported results as expected in December. The Gordondale gas plant is underpinned by a take-or-pay contract and reported results under that contract in December. Fourth quarter results reflect the increased seasonality of earnings due to the addition of new natural gas distribution utilities in August 2012. Natural gas distribution utilities earn the majority of revenue in first and fourth quarters during the winter heating season.

Normalized net income for fourth quarter 2012 was $46.6 million, more than 50 percent increase over $30.8 million reported in fourth quarter 2011. On a per share basis, earnings increased 22 percent to $0.44 compared to $0.36 for same quarter last year. Normalized net income increased primarily due to the acquisitions of SEMCO in August 2012 and PNG in December 2011. Earnings were also driven by the addition of new and expanded gas processing facilities, the addition of new biomass and gas-fired generation assets, colder than normal weather in Alberta, growth in rate base at the natural gas distribution utilities in Nova Scotia and Alberta, and lower depletion at Ikhil. Results for 2011 were negatively impacted due to planned turnarounds in the Gas segment. The 2012 increases were partially offset by the impact of lower frac spread, lower gas volumes processed at some facilities, lower power generated at Bear Mountain, lower transmission revenue and lower approved returns at Nova Scotia utility, Heritage Gas. Interest expense was higher due to higher debt balances as a result of the growth in assets, partially offset by higher capitalized interest and lower interest rates. Income tax expense was higher due to higher net income subject to tax and higher income tax rate applied to earnings in the United States.

Normalized net income adjusts for non-recurring and non-operational type items to better reflect financial performance of the underlying assets. Net income applicable to common shares was normalized for mark-to-market accounting and non-recurring items including $1.2 million of after-tax transaction costs related to the acquisition of SEMCO, after-tax mark-to-market losses of $7.4 million, a one-time after-tax charge of $8.2 million related to the Sundance force majeure arbitration decision, a $2.1 million write-down of assets under development (fourth quarter 2011 – $0.5 million), and $1.1 million of income tax expense related to changes in the future tax rate assumption.

Net income applicable to common shares for fourth quarter 2012 was $26.7 million ($0.25 per share) compared to $31.6 million ($0.36 per share) for same quarter last year.

On a cash flow basis, normalized funds from operations for the three months ended December 31, 2012 increased 78 percent to $112.0 million ($1.07 per share) from $63.0 million ($0.73 per share) in fourth quarter 2011. Normalized EBITDA for fourth quarter 2012 was $129.4 million, a 66 percent increase, compared to $78.1 million for same quarter 2011. The increase was primarily due to the acquisition of SEMCO.

On a consolidated basis, normalized operating income for fourth quarter 2012 was $96.4 million compared to $56.4 million for same quarter 2011. Normalized operating income was driven by the same factors as described above related to normalized net income except for the impact of higher interest and income taxes.

On a consolidated basis, net revenue for fourth quarter 2012 was $207.6 million compared to $156.0 million for same quarter 2011. The increase in net revenue was driven by the same factors impacting normalized operating income in addition to $17.8 million lower mark-to-market gain on risk management contracts and a charge of $11.0 million related to the Sundance force majeure arbitration decision.

Operating and administrative expense for fourth quarter 2012 was $98.7 million compared to $75.5 million in fourth quarter 2011. The increase was primarily due to the addition of SEMCO and PNG, including transaction costs and partially offset by lower operating costs at certain gas facilities as a result of lower power prices and lower volumes processed. Operating cost in fourth quarter 2011 included the planned turnaround at Harmattan.

Amortization expense for fourth quarter 2012 was $35.2 million compared to $21.7 million for same quarter 2011. The increase was due to amortization at SEMCO and PNG as well as other new and expanded assets in Gas and Power, and the write-down of two wind projects under development, partially offset by lower depletion expense at Ikhil. Accretion expense for fourth quarter 2012 was $0.8 million compared to $0.6 million for same quarter 2011.

Interest expense for fourth quarter 2012 was $21.6 million compared to $13.3 million for same quarter 2011. Interest expense increased due to a higher average debt balance of $2,637.3 million (fourth quarter 2011 – $1,179.8 million). The increase was partially offset by higher capitalized interest of $9.7 million (fourth quarter 2011 – $4.4 million) and a lower average borrowing rate of 4.7 percent (fourth quarter 2011 – 6.0 percent).

In fourth quarter 2012, AltaGas recorded income tax expense of $18.5 million compared to $10.5 million in same quarter 2011. In fourth quarter 2012, income taxes were higher compared to same quarter 2011 primarily due to the addition of SEMCO and PNG and partially offset by lower taxes due to lower mark-to-market gains on risk management contracts. In fourth quarter 2012, there was also a charge to income tax expense of $1.1 million related to a statutory rate change.

SENSITIVITY ANALYSIS

The following table illustrates the anticipated effects of possible economic and operational changes on AltaGas' expected 2013 net income.

Factor Share	Increase or decrease	Increase or decrease in net income per share
Gathering and processing volumes	5 Mmcf/d	$0.008
Gathering and processing operating margin per Mcf	1 cent/Mcf	$0.018
Alberta electricity prices [1]	$1/Mwh	$0.010
Natural gas liquids fractionation spread [2]	$1/Bbl	$0.007
Degree day variance from normal – Canadian utilities [3]	5 percent	$0.009
Degree day variance from Normal – U.S. utilities [4]	5 percent	$0.018
Change in Canadian dollar per U.S. dollar exchange rate	$0.05	$0.011

1 *Based on approximately 67 percent of Sundance PPA volumes being hedged.*

2 *Based on approximately 50 percent of frac spread exposed NGL volumes being hedged.*

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

4 *Degree days – U.S. utilities relate to SEMCO Gas and ENSTAR service areas. For U.S. utilities degree days are a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior fifteen years for SEMCO Gas and during the prior ten years for ENSTAR.*

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS [1]

($ millions)	Q4-12	Q3-12	Q2-12	Q1-12	Q4-11	Q3-11	Q2-11	Q1-11
Total revenue	**525.2**	290.7	270.9	363.5	333.6	298.9	304.6	333.6
Net revenue [2]	**207.6**	146.4	144.0	166.6	156.0	115.6	106.2	135.2
Operating income [2]	**81.7**	33.4	29.4	69.6	49.1	33.4	34.3	58.3
Net income before taxes	**51.8**	27.8	33.3	53.5	44.6	18.0	11.8	38.5
Net income applicable to common shares [3]	**26.7**	17.0	21.2	36.9	31.6	11.1	13.3	26.7

($ per share)	Q4-12	Q3-12	Q2-12	Q1-12	Q4-11	Q3-11	Q2-11	Q1-11
Net income applicable to common shares								
Basic [3]	**0.25**	0.17	0.23	0.41	0.37	0.13	0.16	0.32
Diluted [3]	**0.25**	0.17	0.23	0.41	0.36	0.13	0.16	0.32
Dividends declared	**0.36**	0.35	0.345	0.345	0.34	0.33	0.33	0.33

1 Restated to comply with US GAAP.
2 Non-GAAP financial measure. See discussion in the "Non-GAAP Financial Measures" section of this MD&A.
3 Amounts may not add due to rounding.

Significant items that impacted individual quarterly earnings were as follows:

- In first quarter 2011, AltaGas accepted an offer from a producer to sell the Groundbirch facility, resulting in a pre-tax gain of approximately $6.2 million;
- Results in first quarter 2011 were impacted by a settlement of a take-or-pay arrangement resulting in early recognition of pre-tax earnings of $2 million;
- In second quarter 2011, it was determined that a future tax rate of 25 percent more accurately reflected the substantively enacted tax rates anticipated to be in effect in the periods in which the differences between tax and book values are expected to reverse. This resulted in a decrease of future tax liabilities of $6.8 million;
- In the third and fourth quarters 2011, turnarounds at Harmattan and Younger reduced revenue and increased operating expenses resulting in lower operating income of approximately $12 million before taxes. These turnarounds have occurred every three years;
- In fourth quarter 2011, AltaGas acquired all the outstanding common shares of PNG for $224 million including assumed debt of approximately $86 million. In the quarter, AltaGas recorded $5.7 million in pre-tax transaction costs primarily related to the acquisition of PNG and other business development related activities;
- In second quarter 2012, AltaGas recorded $3.5 million gain from the settlement of a dispute with a gas processing customer;
- In third quarter 2012, AltaGas completed the acquisition of SEMCO for total consideration of US$1.156 billion including US$371 million in assumed debt, adding approximately US$725 million in regulated rate base. In the quarter, AltaGas recorded $12.5 million in pre-tax transaction costs and foreign exchange losses primarily related to the acquisition of SEMCO and other business development related activities;
- In fourth quarter 2012, AltaGas wrote down $2.9 million in two wind projects under development; and
- In fourth quarter 2012, AltaGas received independent arbitration panel ruling regarding a claim of force majeure on Sundance B Unit 3 facility. As a result, AltaGas recorded a $11.0 million charge in cost of sales which was previously accrued in accounts receivable.

Consolidated Financial Statements

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The Consolidated Financial Statements and Management's Discussion and Analysis (MD&A) are the responsibility of the management of AltaGas Ltd. (AltaGas or the Corporation) and have been approved by the Board of Directors of the Corporation. The Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (US GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Corporation's financial results. It compares the Corporation's financial and operating performance in 2012 to that in 2011. The MD&A should be read in conjunction with the Consolidated Financial Statements and accompanying notes.

Management is responsible for establishing and maintaining adequate internal controls over financial reporting for the Corporation. Management has designed and maintains a system of internal controls over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. Management undertakes communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the Chairman and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of internal controls over financial reporting. Management concluded, based on its evaluation, that internal controls over financial reporting are effective as of December 31, 2012, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The MD&A and 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 Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal controls and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Consolidated Financial Statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed Ernst & Young LLP as independent external auditors to express an opinion as to whether the Consolidated Financial Statements present fairly, in all material respects, the Corporation's consolidated financial position, results of operations and cash flows in accordance with US GAAP. The report of Ernst & Young LLP outlines the scope of its examination and its opinion on the Consolidated Financial Statements.

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

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

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 as at December 31, 2012 and 2011, and the consolidated statements of income, comprehensive income and accumulated other comprehensive (loss) income, equity 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 United States 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, 2012 and 2011 and the results of its operations and its cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

Ernst + Young LLP

Calgary, Canada
February 27, 2013

Ernst & Young LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

As at *($ thousands)*	**December 31 2012**	December 31 2011
		(restated)
ASSETS		
Current assets		
Cash and cash equivalents	**$ 11,827**	$ 2,875
Accounts receivable *(note 16)*	**382,610**	234,534
Inventory *(note 4)*	**94,709**	12,467
Restricted cash holdings from customers	**28,626**	19,672
Regulatory assets *(note 15)*	**4,344**	5,141
Risk management assets *(note 16)*	**47,788**	68,404
Prepaid expenses and other current assets	**21,456**	8,642
	591,360	351,735
Property, plant and equipment *(note 5)*	**3,949,166**	2,486,050
Intangible assets *(note 6)*	**189,790**	177,516
Goodwill *(note 7)*	**714,902**	281,123
Regulatory assets *(note 15)*	**275,263**	125,271
Risk management assets *(note 16)*	**18,132**	21,642
Long-term investments and other assets *(notes 8 and 21)*	**24,969**	25,406
Investments accounted for by equity method *(note 9)*	**148,358**	87,483
	$5,911,940	$3,556,226
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 13)*	**$ 370,011**	$ 314,422
Dividends payable	**12,640**	10,264
Short-term debt *(note 10)*	**66,938**	16,824
Current portion of long-term debt *(note 11)*	**9,302**	105,962
Customer deposits	**51,756**	25,570
Regulatory liabilities *(note 15)*	**1,971**	503
Risk management liabilities *(note 16)*	**39,734**	72,973
Other current liabilities	**10,301**	11,352
	562,653	557,870
Long-term debt *(note 11)*	**2,626,086**	1,214,298
Asset retirement obligations *(note 12)*	**56,632**	44,318
Deferred income taxes *(note 14)*	**391,274**	265,834
Regulatory liabilities *(note 15)*	**104,282**	26,686
Risk management liabilities *(note 16)*	**10,526**	20,608
Other long-term liabilities	**33,786**	28,810
Future employee obligations *(note 20)*	**126,904**	37,014
	3,912,143	2,195,438

CONSOLIDATED BALANCE SHEETS (continued)

As at *($ thousands)*	**December 31 2012**	December 31 2011
		(restated)
Shareholders' equity		
Common shares, no par value; unlimited shares authorized; 105.34 million issued and outstanding *(note 17)*	**1,639,895**	1,204,269
Preferred shares Series A cumulative redeemable five-year; par value $25; authorized 8 million; 8 million issued and outstanding *(note 17)*	**194,126**	194,126
Preferred shares Series C cumulative redeemable five-year; par value US$25; authorized 8 million; 8 million issued and outstanding *(note 17)*	**200,626**	–
Contributed surplus	**10,570**	7,441
Accumulated deficit	**(69,979)**	(38,634)
Accumulated other comprehensive loss	**(15,447)**	(11,840)
Total shareholders' equity	**1,959,791**	1,355,362
Non-controlling interests	**40,006**	5,426
	$5,911,940	$3,556,226

Commitments and contingent liabilities *(note 19)*

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 STATEMENT OF INCOME

For the years ended December 31 *($ thousands except per share amounts)*	**2012**	2011
		(restated)
REVENUE		
Operating	**$1,427,623**	$1,289,032
Unrealized gain (loss) on risk management contracts *(note 16)*	**22,057**	(9,003)
Other revenue (expenses)	**580**	(9,436)
	1,450,260	1,270,593
EXPENSES		
Cost of sales, exclusive of items shown separately	**852,313**	832,844
Operating and administrative	**323,244**	264,889
Accretion of asset retirement obligations *(note 12)*	**3,115**	2,446
Depreciation, depletion and amortization *(notes 5 and 6)*	**102,128**	79,685
	1,280,800	1,179,864
Income from equity investments	**66,597**	75,356
Foreign exchange loss	**8,512**	383
Interest expense		
Short-term debt	**1,552**	5,836
Long-term debt	**59,685**	46,871
Income before income taxes	**166,308**	112,995
Income tax expense *(note 14)*		
Current	**8,973**	4,052
Deferred	**37,077**	16,213
Net income after taxes	**120,258**	92,730
Net income applicable to non-controlling interests	**3,489**	–
Net income applicable to controlling interests	**116,769**	92,730
Preferred share dividends	**14,922**	10,000
Net income applicable to common shares	**$ 101,847**	$ 82,730
Net income per common share *(note 18)*		
Basic	**$ 1.07**	$ 0.98
Diluted	**$ 1.06**	$ 0.97
Weighted average number of common shares outstanding *(notes 17 and 18)* *(thousands)*		
Basic	**94,986**	84,042
Diluted	**96,311**	85,207

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)*	**2012**	2011
		(restated)
Net income after taxes	**$120,258**	$ 92,730
Other comprehensive (loss) income		
Adjustments to pension and other post-retirement benefit plan liabilities *(note 20)* [1]	**(7,103)**	(1,453)
Change in fair value of derivatives utilized for hedging purpose *(note 16)* [2]	**–**	67
Reclassification of change in fair value of derivatives to net income *(note 16)*	**1,809**	628
Unrealized gain (loss) on available-for-sale assets *(notes 8 and 16)* [3]	**108**	(7,352)
Foreign currency translation adjustments	**3,842**	–
Foreign exchange loss on long-term debt designated as a hedge [4]	**(2,263)**	–
Total other comprehensive loss attributable to common shareholders (net of tax)	**(3,607)**	(8,110)
Comprehensive income attributable to common shareholders and non-controlling interests (net of tax)	**$116,651**	$ 84,620
Accumulated other comprehensive loss, beginning of period (net of tax)	**$ (11,840)**	$ (3,730)
Other comprehensive loss (net of tax)	**(3,607)**	(8,110)
Accumulated other comprehensive loss, end of period (net of tax)	**$ (15,447)**	$(11,840)

1 *Net of tax recovery of $2,480 thousand for the year ended December 31, 2012 (2011 – $1,047 thousand).*

2 *Net of tax expense of $nil for the year ended December 31, 2012 (2011 – $56 thousand).*

3 *Net of tax expense of $356 thousand for the year ended December 31, 2012 (2011 – $1,069 thousand).*

4 *Net of tax recovery of $323 thousand for the year ended December 31, 2012 (2011 – $nil).*

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF EQUITY

For the years ended December 31 *($ thousands)*	2012	2011
		(restated)
Common shares *(note 17)*		
Balance, beginning of period	**$1,204,269**	$1,023,033
Shares issued for cash on exercise of options	**16,197**	7,181
Shares issued under DRIP [1]	**41,071**	34,681
Shares issued on public offering	**–**	139,374
Shares issued on conversion of subscription receipts	**378,358**	–
Balance, end of period	**1,639,895**	1,204,269
Preferred shares *(note 17)*		
Balance, beginning of period	**194,126**	194,126
Series C issued	**200,626**	–
Balance, end of period	**394,752**	194,126
Contributed surplus		
Balance, beginning of period	**7,441**	5,672
Share options expense	**4,032**	2,099
Exercise of share options	**(649)**	(141)
Forfeiture of share options	**(254)**	(189)
Balance, end of period	**10,570**	7,441
Accumulated deficit		
Balance, beginning of period	**(38,634)**	(9,210)
Net income applicable to controlling interests	**116,769**	92,730
Acquisition of non-controlling interest	**(405)**	–
Common share dividends	**(132,787)**	(112,154)
Preferred share dividends – Series A	**(10,000)**	(10,000)
Preferred share dividends – Series C	**(4,922)**	–
Balance, end of period	**(69,979)**	(38,634)
Accumulated other comprehensive loss		
Balance, beginning of period	**(11,840)**	(3,730)
Other comprehensive loss attributable to common shareholders	**(3,607)**	(8,110)
Balance, end of period	**(15,447)**	(11,840)
Total shareholders' equity	**1,959,791**	1,355,362
Non-controlling interests		
Balance, beginning of period	**5,426**	–
Net income applicable to non-controlling interests	**3,489**	–
Business acquisition *(note 3)*	**36,439**	5,426
Acquisition of non-controlling interests	**(5438)**	–
Distribution by subsidiaries to non-controlling interests	**(1,357)**	–
Contributions from subsidiaries to non-controlling interests	**1,447**	–
Balance, end of period	**40,006**	5,426
Total equity	**$1,999,797**	$1,360,788

1 Dividend Reinvestment and Optional Share Purchase Plan.

See accompanying notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 *($ thousands)*	**2012**	2011
		(restated)
Cash from operations		
Net income after taxes	**$120,258**	$92,730
Items not involving cash:		
Depreciation, depletion and amortization	**102,128**	79,685
Accretion of asset retirement obligations	**3,115**	2,446
Share-based compensation	**3,129**	1,769
Deferred income tax expense	**37,077**	16,213
Gain on sale of assets	**(73)**	(6,172)
Income from equity investments	**(66,597)**	(75,356)
Unrealized (gains) losses on risk management contracts	**(22,057)**	9,003
Unrealized (gains) losses on held-for-trading investments	**(173)**	9,149
Other	**3,734**	1,164
Asset retirement obligations settled	**(2,329)**	(851)
Distributions from equity investments	**73,978**	82,573
Changes in operating assets and liabilities		
Accounts receivable	**(107,977)**	(26,952)
Inventory	**(10,050)**	(264)
Other current assets	**17,135**	(2,948)
Regulatory assets (current)	**827**	(5,139)
Accounts payable and accrued liabilities	**33,742**	9,216
Customer deposits	**4,763**	4,138
Regulatory liabilities (current)	**1,147**	(991)
Other current liabilities	**(17,849)**	288
Other operating assets and liabilities	**(27,571)**	(4,299)
	146,357	185,402
Investing activities		
Change in restricted cash holdings from customers	**(6,802)**	(2,048)
Acquisition of property, plant and equipment	**(768,651)**	(400,173)
Acquisition of intangible assets	**(52,809)**	(32,957)
Proceeds from disposition of property, plant and equipment	**18,261**	12,100
Contributions to equity investments	**(2,606)**	(3,260)
Business acquisitions, net of cash acquired	**(806,014)**	(138,020)
Acquisition of non-controlling interest	**(5,843)**	–
	(1,624,464)	(564,358)

CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)

For the years ended December 31 *($ thousands)*	**2012**	2011
		(restated)
Financing activities		
Net issuance (repayment) of short-term debt	**48,905**	(73,046)
Issuance of long-term debt, net of debt issuance costs	**1,053,949**	397,738
Repayment of long-term debt	**(105,071)**	(1,787)
Dividends – common shares	**(130,411)**	(111,869)
Dividends – preferred shares	**(14,922)**	(10,000)
Distributions to non-controlling interest	**(1,357)**	–
Distributions from non-controlling interest	**1,447**	–
Net proceeds from issuance of common shares	**435,626**	179,772
Net proceeds from issuance of preferred shares	**198,975**	–
	1,487,141	380,808
Effect of exchange rate changes on cash and cash equivalents	**(82)**	–
Change in cash and cash equivalents	**8,952**	1,852
Cash and cash equivalents, beginning of period	**2,875**	1,023
Cash and cash equivalents, end of period	**$ 11,827**	$ 2,875

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

For the years ended December 31 *($ thousands)*	**2012**	2011
Interest paid (net of capitalized interest)	**$ 20,668**	$31,896
Income taxes paid	**$ 11,824**	$ 3,037

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 Canadian dollars unless otherwise indicated.)

1. ORGANIZATION AND OVERVIEW OF BUSINESS

The material businesses of AltaGas Ltd. (AltaGas or the Corporation) are operated by the Corporation, AltaGas Holding Partnership, AltaGas Pipeline Partnership, AltaGas Services (U.S.) Inc., AltaGas Processing Partnership, AltaGas Utility Group Inc. (Utility Group), and AltaGas Utility Holdings (Pacific) Inc. (collectively the operating subsidiaries).

AltaGas is a diversified energy infrastructure business with a focus on natural gas, power and regulated utilities. AltaGas has three operating segments, Gas, Power and Utilities. AltaGas' Gas segment serves producers in the Western Canada Sedimentary Basin (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and fractionation, transmission, storage and natural gas marketing.

The Power segment includes 589 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets. AltaGas owns 50 percent of the Sundance B Power Purchase Arrangements (PPA), giving it the rights to power output and ancillary services from coal-fired base-load generation until December 31, 2020. Further generation is in various stages of construction including the Northwest run-of-river projects (Northwest Projects), which consist of the Forrest Kerr run-of-river project (Forrest Kerr Project), McLymont Creek run-of-river project (McLymont Creek Project), and Volcano Creek run-of-river project (Volcano Creek Project). The 277 MW Northwest Projects are contracted with 60-year Consumer Price Index (CPI) indexed Energy Purchase Arrangements (EPA) with BC Hydro, as well as Impact Benefit Agreements with the Tahltan First Nation. Forrest Kerr Project is expected to be in service in mid-2014. The Mclymont Creek Project and Volcano Creek Project are expected to be in service in late 2015.

The Utilities segment is predominantly comprised of natural gas distribution rate-regulated utilities, where financial results are generally based on a regulated allowed return on capital invested. AltaGas owns and operates regulated natural gas utilities in Canada and United States. The utilities are generally allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of capital from the regulator approved capital investment base.

The regulated utilities businesses in Canada are natural gas distribution utilities and are comprised of AltaGas Utilities Inc. (AUI) in Alberta, Pacific Northern Gas Ltd. (PNG) in British Columbia and Heritage Gas Limited (Heritage Gas) in Nova Scotia. AltaGas also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. Through Heritage Gas, AltaGas is also developing and constructing a non-rate-regulated compressed natural gas (CNG) distribution business in Nova Scotia.

On August 30, 2012, the Corporation acquired all of the issued and outstanding shares of Semco Holding Corporation (SEMCO). SEMCO is the sole shareholder of SEMCO Energy Inc. (SEMCO Energy), a rate-regulated utility company headquartered in Port Huron, Michigan, with natural gas distribution and natural gas storage operations in Alaska and Michigan. As a result of the SEMCO acquisition, the Utilities business in the United States is comprised of SEMCO Energy Gas Company (SEMCO Gas) in Michigan and ENSTAR Natural Gas Company (ENSTAR) and a 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

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

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

These Consolidated Financial Statements of AltaGas include the accounts of the Corporation and all of its wholly owned subsidiaries, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities of the joint venture or partnership. Note 9 to these Consolidated Financial Statements lists the Corporation's joint ventures.

Transactions between and amongst, AltaGas and its wholly owned subsidiaries, and the proportionate interests in joint ventures or partnerships are eliminated on consolidation. Where there is a party with a non-controlling interest in a subsidiary that AltaGas controls, that non-controlling interest is reflected as "Non-controlling interests" in the Consolidated Financial Statements. The non-controlling interests in net income (or loss) of consolidated subsidiaries is shown as an allocation of the consolidated net income and is presented separately in "Net income applicable to non-controlling interests".

Note 24 to these Consolidated Financial Statements details the Canadian GAAP to US GAAP transition and reconciliation information.

SIGNIFICANT ACCOUNTING POLICIES

Business Acquisitions

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

Rate-Regulated Operations

SEMCO Energy, AUI, PNG and Heritage Gas (collectively "Utilities") engage in the delivery and sale of natural gas and are regulated by the Michigan Public Service Commission (MPSC) and Regulatory Commission of Alaska (RCA), Alberta Utilities Commission (AUC), British Columbia Utilities Commission (BCUC) and the Nova Scotia Utility and Review Board (NSUARB), respectively.

The MPSC, RCA, AUC, BCUC 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 MPSC, RCA, AUC, BCUC 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 US GAAP for entities not subject to rate regulation.

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to 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 expected to be refunded to customers through the rate-setting process.

Cash and Cash Equivalents

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

Accounts Receivable

Receivables are recorded net of the allowance for doubtful accounts in the accompanying Consolidated Balance Sheets. AltaGas regularly analyzes and evaluates the collectability of the accounts receivable based on a combination of factors. If circumstances related to the collectability change, the allowance for doubtful accounts is further adjusted. Accounts are written off when collection efforts are complete and future recovery is unlikely.

Inventory

Inventory consists of materials, supplies and NGL, which are valued at the lower of cost or net realizable value. Cost of inventory is assigned using a weighted average cost formula. Gas inventory held in storage is reported at average cost. In general, commodity costs and variable transportation costs are capitalized as gas in underground storage. Fixed costs, primarily pipeline demand charges and storage charges, are expensed as incurred through the cost of gas.

Restricted Cash Holdings from Customers

Cash deposited which is restricted and is not available for general use by AltaGas is separately presented as restricted cash holdings in the Consolidated Balance Sheet.

Property, Plant and Equipment (PPE), and Depreciation and Amortization

Property, plant and equipment are carried at cost. The Corporation depreciates the cost of capital assets, net of salvage value, on a straight-line basis over the estimated useful life of the assets, with the exception of rate-regulated utilities assets, where depreciation is calculated on a straight-line basis or over the contract term of a specific agreement at rates as approved by the regulatory authorities.

The U.S. utilities include in depreciation expense an amount allowed for regulatory purposes to be collected in current rates for future removal and site restoration costs. The Canadian utilities that collect future removal and site restoration costs in rates defer the revenue until the costs are incurred.

Interest costs are capitalized on major additions to property, plant and equipment until the asset is ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on AltaGas' prior quarter actual borrowing long-term debts interest rate, unless AltaGas borrowed funds specifically for the purpose of obtaining an asset. In this case, the interest costs to be capitalized are calculated using the actual interest rate applicable to the funds obtained for that asset.

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

The range of useful lives for AltaGas' property, plant and equipment is as follows:

Gas	
Extraction and transmission (E&T)	15-45 years
Field gathering and processing (FG&P)	15-36 years
Other	1-32 years
Power generation assets	5-30 years
Utilities assets	3-80 percent
Corporate assets	1-5 years

As required by the respective regulatory authorities, net additions to utility assets at Heritage Gas and PNG are not depreciated until the year after they are brought into active service and net additions to utility assets at AUI and SEMCO Energy are depreciated commencing in the year in which the assets are brought into active service.

Generally, when a regulated asset is retired or disposed of, there is no gain or loss recorded in income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future depreciation expense when it is refunded or collected in rates.

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.

Intangible Assets

Intangible assets are recorded at cost, and are amortized on a straight-line basis over their term or estimated useful life:

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

Energy services relationships are amortized on a straight-line basis over the expected useful life of the relationships.

The E&T contracts are amortized on a straight-line basis over the average expected life of the contracts.

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

Goodwill

Goodwill represents that portion of the consideration on acquisitions which was in excess of the fair value of the net assets acquired. Goodwill is not subject to amortization but assessed at least annually for impairment, or more often when impairment indicators exist. If an impairment test of goodwill shows that the carrying amount of the goodwill is in excess of the fair value, a corresponding impairment loss would be recorded in the Consolidated Statement of Income.

Impairment of Long-Lived Assets

If facts and circumstances suggest that a long-lived asset or an intangible asset may be impaired, the carrying value is reviewed. If this review indicates that the value of the asset is not recoverable, as determined by the projected undiscounted cash flows related to the asset over its remaining life, then the carrying value of the asset is reduced to its estimated fair value less cost to sell.

Financial Instruments

Financial instruments are recorded using the mark-to-market method of accounting for transactions under derivative contracts for which AltaGas is not permitted, or does not elect, to use accrual accounting or hedge accounting in order to match the earnings impact of those activities to the greatest extent permissible. Under the mark-to-market method of accounting, the fair value of these contracts is recorded as derivative assets and liabilities at the time of contract execution.

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

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

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

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a stand-alone derivative and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in income. All derivatives, other than those that meet the normal purchase and normal sale (NPNS) exemption, are carried on the Consolidated Balance Sheet at fair value. A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to AltaGas' business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, AltaGas intends to receive physical delivery of the commodity, and AltaGas deems the counterparty credit worthy. AltaGas continually assesses the contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Offsetting

Offsetting of fair value amounts is generally not applied except where a right of set-off exists. A right of set-off exists only if and when AltaGas and its counterparty in the financial instrument owe a determinable amount, the two parties agreed to set-off the amounts due, AltaGas intends to set-off, and the right of set-off is enforceable by law.

Hedges

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

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

AltaGas designated some of its U.S. dollar-denominated long-term debt as a foreign currency hedge of its investment in foreign operations. Accordingly, foreign exchange gains and losses, from the dates of designation, on the translation of the U.S. dollar-denominated long-term debt are included in OCI.

Long-Term Investments and Other Assets

Long-term investments are recorded at cost or designated as available-for-sale or held-for-trading. Investments in equity instruments that do not have a quoted market price in an active market are measured at cost.

Investments Accounted for by Equity Method

Investments in entities in which AltaGas has the ability to exercise significant influence but not control, are accounted for using the equity method.

AltaGas accounts for its investments in less than majority owned corporate joint ventures and affiliates (equity investments) under the equity method. AltaGas applies the equity method to the equity investments when it has the ability to exercise significant influence over the operating and financial policies of the joint venture and affiliate. Under this method, the assets and liabilities of the joint ventures and affiliates are not consolidated. The investments in net assets of the equity investments are recorded in the Consolidated Balance Sheets in "Investments accounted for by equity method". The gain or loss from operations of the joint ventures and affiliates is reported on a net basis in the Consolidated Statement of Income under the caption "Income from equity investments".

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 continue to be 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 of benefit, beginning at the commencement of commercial operations.

Asset Retirement Obligations

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

Revenue Recognition

In the Gas and Power reporting segments, revenue is recognized at the time the product or service is delivered.

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

Realized gains and losses from risk management activities related to commodity prices are recognized when the sale occurs or when the underlying financial asset or financial liability is removed from the Consolidated Balance Sheet items “Risk management assets” or “Risk management liabilities”. 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.

Transaction costs for obtaining debt financing are capitalized and included under “Long-term investments and other assets” on the Consolidated Balance Sheet. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheet. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in interest expense on the Consolidated Statement of Income.

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency for domestic entities are converted at the exchange rate in effect at the balance sheet date. Adjustments resulting from the conversion are recorded in the Consolidated Statement of Income. Non-monetary assets and liabilities are converted at the exchange rate in effect at the transaction date. Revenues and expenses are converted at the exchange rate applicable at the transaction date.

For foreign entities with a functional currency other than Canadian dollars, AltaGas' reporting currency, assets and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. The exchange rate used to convert a U.S. dollar to a Canadian dollar for the year ended December 31, 2012 was 0.9949 (December 31, 2011 – 1.0482). Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in OCI. The average exchange rate used to convert a U.S. dollar to a Canadian dollar for the year ended December 31, 2012 was 0.9837 (December 31, 2011 – 0.9891).

Share-Based Compensation Plans

AltaGas follows the fair value method of accounting for share options granted to certain employees and directors. 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' equity.

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

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

Pension Plans and Post-Retirement Benefits

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

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated on service with a reasonable range of expected plan investment performance and management's best estimate of 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 12.3 years and 12.4 years, respectively.

Unamortized actuarial gains (losses) and transitional obligations for non-utility plans are initially recognized in the other comprehensive income (losses) and amortized on a straight-line basis over the average remaining service life of active employees for the respective plan through the income statement. Utilities recognize unamortized actuarial gains (losses) and transitional obligations for pension plans and post-retirement benefits under regulatory and other liabilities.

Income Taxes

Income taxes for the Corporation and its subsidiaries are calculated using the liability method of tax accounting. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax bases of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized.

Investment tax credits are deferred and amortized over the estimated service lives of the related properties.

The rate-regulated natural gas distribution subsidiaries recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be recovered from or paid to customers in the future.

Net Income per Share

Basic and diluted net income applicable to common shares are computed respectively using the weighted average number of common shares and the weighted average number of common shares that could potentially dilute earnings during a reporting period (share-based compensation awards). Net income applicable to common shares is the difference between the net income applicable to controlling interests less preferred share dividends.

The potentially dilutive impact of the share-based compensation awards is determined using the treasury stock method. Under the treasury stock method, awards are treated as if they had been exercised with any proceeds used to repurchase common stock at the average market price during the period. Any incremental difference between the assumed number of shares issued and purchased is included in the diluted share computation.

The computation of the diluted net income applicable to common shares excludes the anti-dilutive instruments. These anti-dilutive instruments were due to certain share-based compensation awards calculated under the treasury stock method. This anti-dilution occurs where the exercise prices are higher than the average market value of AltaGas' stock-price during the applicable period.

Emission Credits

Emission credits purchased or generated internally are recorded at fair value and included in other current assets. As no active market currently exists, emission credits are recorded at cost.

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

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

CHANGE IN ACCOUNTING POLICIES

Balance Sheet Disclosures – Offsetting Assets and Liabilities

In December 2011, the Financial Accounting Standards Board (FASB) issued an accounting standards update which requires companies to disclose gross information and net information about both instruments and transactions eligible for offset in the statement of financial positions and instruments and transactions subject to an agreement similar to a master netting arrangement to enable users of its financial statements to understand the effect of those arrangements on its financial position. Accounting Standards Update (ASU) Number (No.) 2011-11 is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013 with required disclosures made retrospectively for all comparative periods presented. AltaGas does not expect the implementation of this disclosure guidance to have a material impact on its financial statements.

Asset impairment – Intangible Assets and Goodwill

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

In July 2012, FASB issued ASU 2012-02, an amendment to Accounting Standards Codification (ASC) 350-30 whereby an entity first assesses qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired as a basis for determining whether it is necessary to perform the quantitative impairment test, which results in a guidance similar to the goodwill impairment testing. This amendment does not have any impact for the preparation and presentation of AltaGas' Consolidated Financial Statements.

Comprehensive Income and Equity

In June 2011, FASB issued ASU No. 2011-05, "Other Comprehensive Income". This standard amends ASC 220 to improve the comparability, consistency and transparency of comprehensive income reporting. The adoption of this update changes the order in which certain financial statements are presented and provide additional detail on those financial statements where applicable, but will not have any other impact to the financial statements. In December 2011, FASB issued ASU No. 2011-12 "Deferral of the Effective Date for Amendments to the Presentation of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05". The amendments of this ASU are effective January 1, 2012 as the amendments in ASU No. 2011-05, except for the presentation requirements for the reclassification adjustments out of accumulated other comprehensive income, which have been deferred by ASU No. 2011-12.

3. BUSINESS ACQUISITION

SEMCO

On August 30, 2012, AltaGas, through a wholly owned subsidiary, acquired 100 percent of SEMCO.

SEMCO owns SEMCO Energy a rate-regulated utility company headquartered in Port Huron, Michigan. SEMCO Energy's primary business is the transmission, distribution and sale of natural gas to its customers. SEMCO Energy's gas distribution business distributes and transports natural gas for approximately 296,000 customers in Michigan and approximately 134,000 customers in Alaska. The gas distribution business is subject to regulation by the MPSC in Michigan and the RCA in Alaska. SEMCO Energy's other businesses primarily include operations and investments in propane distribution, intrastate natural gas pipelines and natural gas storage facilities. SEMCO Energy owns a 65 percent interest in the CINGSA in-field storage facility in the Cook Inlet area of Alaska.

AltaGas paid an aggregate purchase price of $1,137.0 million (after adjustments) including $365.7 million in assumed debt. Transaction costs related to the acquisition were $7.1 million, which have been expensed in the Consolidated Statement of Income within "Operating and administrative expenses".

Below is a provisional purchase price allocation based on the statement of financial position as at August 30, 2012, using an exchange rate of 0.9863 to convert U.S. dollar to Canadian dollar.

	SEMCO
Cash consideration	$780,703
Less cash acquired	(9,388)
Total consideration	771,315
Purchase price allocation	
Assets acquired:	
Current assets	$112,894
PPE	803,123
Regulatory assets	140,209
Goodwill	430,610
Long-term investments and other assets	40,248
	1,527,084
Less liabilities assumed:	
Current liabilities	$ 67,184
Long-term debt	365,696
Deferred income taxes	96,189
Regulatory liabilities	75,443
Other long-term liabilities	125,827
Accumulated other comprehensive income	(498)
	729,841
Non-controlling interest	$ 25,928
	$ 771,315

The non-controlling interest has been recognized in the provisional purchase price allocation at its fair value.

The valuation technique used to measure the acquisition-date fair value of the assets and liabilities of SEMCO was book value for regulated assets given the regulatory environment in which SEMCO operates. Non-regulated assets were measured based using cost and market approach. The valuation resulted in the recognition of $430.6 million of non-taxable goodwill.

For the period August 30, 2012 to December 31, 2012, SEMCO recorded revenues of $220.3 million and net income of $14.4 million. Had the acquisition occurred on January 1, 2012, AltaGas pro-forma consolidated revenue would have been approximately $1,880.5 million and consolidated net income of $119.0 million for the year ended December 31, 2012. This pro-forma financial information is not necessarily indicative of what the financial results of operations would have been had the acquisition been completed at January 1, 2012.

Decker Energy International Inc.

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

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

	DEI
Cash consideration	$34,724
Less cash acquired	(25)
Total consideration	34,699
Purchase price allocation	
Assets acquired:	
Current assets	$ 389
Long-term investments and other assets	46,551
	46,940
Less liabilities assumed:	
Current liabilities	$ 1,725
Non-controlling interest	$ 10,516
	$34,699

The non-controlling interest has been recognized in the provisional purchase price allocation as the proportionate share of the acquired identified net assets.

4. INVENTORY

	December 31 2012	December 31 2011
		(restated)
Natural gas held in storage	**$86,005**	$ 10,081
Other inventory	**8,704**	2,386
	$94,709	$12,467

5. PROPERTY, PLANT AND EQUIPMENT

	2012			2011 *(restated)*		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
Gas						
E&T assets	**$1,137,218**	**$(174,365)**	**$ 962,853**	$1,028,781	$(148,924)	$ 879,857
FG&P assets	**1,074,891**	**(282,443)**	**792,448**	819,795	(255,136)	564,659
Energy services assets	**1,808**	**(1,368)**	**440**	1,453	(1,385)	68
Other assets	**13,821**	**(10,157)**	**3,664**	11,778	(9,174)	2,604
Power						
Capital lease	**–**	**–**	**–**	13,798	(10,117)	3,681
Power generation assets	**853,375**	**(28,276)**	**825,099**	536,914	(17,143)	519,771
Utilities	**1,376,010**	**(27,764)**	**1,348,246**	512,958	(16,025)	496,933
Corporate						
Other assets	**21,930**	**(5,514)**	**16,416**	21,478	(3,001)	18,477
	$4,479,053	**$(529,887)**	**$3,949,166**	$2,946,955	$(460,905)	$2,486,050

Interest capitalized on long-term capital construction projects for the year ended December 31, 2012 was $35.2 million (2011 – $11.0 million).

As at December 31, 2012, the Corporation had spent approximately $578.7 million (2011 – $531.7 million) on capital projects under construction that were not yet subject to amortization. In 2012, two wind projects under development were written down due to their unlikely probability to reach commercial operations.

Depreciation expense related to property, plant and equipment for the year ended December 31, 2012 was $94.3 million (2011 – $71.4 million). Within depreciation expense for the year ended December 31, 2012, $2.9 million for write-down of property, plant and equipment was included (2011 – $0.6 million).

Net additions to Utilities assets at PNG and Heritage Gas are not amortized until the year after they are brought into active service as required by the respective regulating authorities. Utilities assets not yet subject to amortization were $31.9 million as at December 31, 2012 (December 31, 2011 – $25.0 million).

6. INTANGIBLE ASSETS

	2012			2011 *(restated)*		
	Cost	Accumulated amortization	Net book value	Cost	Accumulated amortization	Net book value
E&T contracts	**$ 57,798**	**$(16,616)**	**$ 41,182**	$ 57,798	$(13,816)	$ 43,982
Electricity service agreement	**90,000**	**–**	**90,000**	90,000	–	90,000
Energy services relationships	**20,892**	**(9,494)**	**11,398**	20,892	(8,101)	12,791
Computer software	**54,030**	**(23,762)**	**30,268**	36,750	(20,330)	16,420
Land rights	**15,853**	**(1,571)**	**14,282**	13,437	(1,505)	11,932
Franchises and consents	**3,622**	**(962)**	**2,660**	3,014	(623)	2,391
	$242,195	**$(52,405)**	**$189,790**	$221,891	$(44,375)	$ 177,516

Amortization expense related to intangible assets for the year ended December 31, 2012 was $7.8 million (2011 – $8.3 million).

The following table sets forth the estimated amortization expense of intangible assets for the years ended December 31:

2013	$ 10,477
2014	11,016
2015	11,633
2016	11,056
2017	9,657
Thereafter	$135,589

The electricity service agreement relates to a 60-year CPI indexed EPA not yet subject to amortization.

7. GOODWILL

	2012	2011 *(restated)*
Balance, beginning of year	**$281,123**	$222,602
Business acquisition	**430,024**	58,595
Foreign exchange translation	**3,755**	–
US GAAP transitional adjustment *(note 24)*	**–**	(74)
Balance, end of year	**$714,902**	$281,123

In 2008, the Corporation recognized $143.7 million of goodwill on the acquisition of 100 percent interest in Taylor NGL Limited Partnership (Taylor). In 2009, the Corporation recognized $61.2 million of goodwill on the acquisitions of 100 percent interests in AUI and Heritage Gas. In 2010, the Corporation recognized $17.7 million of goodwill on the acquisition of 100 percent interest in Landis Energy Corporation. In 2011, the Corporation recognized $58.6 million on the acquisition of 100 percent interest in PNG. In 2012, the Corporation recognized $430.6 million on the acquisition of 100 percent interest in SEMCO.

Goodwill has been assessed for impairment with no evidence of an impairment loss.

8. LONG-TERM INVESTMENTS AND OTHER ASSETS

	December 31 2012	December 31 2011
		(restated)
Investments in publicly-traded entities	**$ 7,151**	$ 6,819
Investment in private equities	**864**	310
Debt financing costs	**14,818**	12,407
Other	**2,136**	5,870
	$ 24,969	$ 25,406

In January 2009, AltaGas purchased common shares of Alterra Power Corp. (Alterra), (formerly Magma Energy Corp.), through a private equity offering. These shares were classified as available-for-sale. The accumulated changes in fair value of these common shares are being reported in OCI, as an unrealized pre-tax loss of $5.8 million as at December 31, 2012 (December 31, 2011 – unrealized pre-tax loss of $6.0 million).

In July 2009, AltaGas purchased additional shares of Alterra as part of its initial public offering. These shares were classified as held-for-trading. In July 2010, AltaGas purchased a second tranche of common shares in Alterra, which were classified as held-for-trading. All shares of Alterra are reported under “Long-term investments and other assets”.

Unrealized gains (losses) on held-for-trading are recognized in the Consolidated Statement of Income under “Other revenue (expense)”.

The investments classified as available-for-sale also include funds under trust, acquired with SEMCO, with unrealized pre-tax loss of $54 thousand as at December 31, 2012.

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

	December 31 2012	December 31 2011
		(restated)
Financial assets held-for-trading	**$173**	$(9,149)

9. JOINT VENTURES

AltaGas accounts for its investments in joint ventures where the Corporation has an undivided interest in the assets and liabilities using the proportionate consolidation method and in joint ventures with jointly controlled interests using the equity method of accounting. The proportionate consolidation and equity methods are applied using the pro-rata share of interest owned by AltaGas. The following table lists the Corporation’s joint ventures as at December 31, 2012:

Description	Location	Ownership Percentage	Accounting Method
Alton Natural Gas Storage Inc.	Canada	50	Equity
Alton Natural Gas Storage LP	Canada	50	Equity
ASTC Partnership	Canada	50	Equity
Busch Ranch Wind Project	United States	50	Proportionate
Craven County Wood Energy GP	United States	50	Equity
Craven County Wood Energy LP	United States	50	Equity
Eaton Rapids Gas Storage System	United States	50	Equity
Edmonton Ethane Extraction Plant (EEEP)	Canada	48.667	Proportionate
Empress ATCO (EGLJV)	Canada	7.20	Proportionate
Empress Provident (PEEP)	Canada	11.25	Proportionate
Gilby Midstream	Canada	50	Proportionate
Grayling Generating Station GP	United States	50	Equity
Grayling Generating Station LP	United States	50	Equity
Ikhil Joint Venture	Canada	33.334	Proportionate
Inuvik Gas Ltd.	Canada	33.333	Equity
Sarnia Airport Storage Pool LP	Canada	50	Equity
Sarnia Airport Storage Pool Management Inc.	Canada	50	Equity
Younger	Canada	56.667	Proportionate

The tables below represent 100 percent of the investee financial information as at December 31, 2012 and 2011, which AltaGas accounts for using the proportionate consolidation and equity accounting methods.

As at December 31, 2012	Proportionate Consolidation Method	Equity Method	Total
Revenues	**$149,561**	**$ 351,632**	**$ 501,193**
Expenses	**109,209**	**228,277**	**337,486**
	$ 40,352	**$ 123,355**	**$ 163,707**
Current assets	**56,149**	**91,438**	**147,587**
Property, plant and equipment	**313,845**	**112,094**	**425,939**
Intangible assets	**16,000**	**98,072**	**114,072**
Long-term investments and other assets	**1**	**5,013**	**5,014**
Current liabilities	**(15,674)**	**(83,844)**	**(99,518)**
Other long-term liabilities	**(5,263)**	**(5,401)**	**(10,664)**
Operating activities	**54,282**	**145,208**	**199,490**
Investing activities	**(22,824)**	**(5,457)**	**(28,281)**
Financing activities	**$ (25,252)**	**$(133,814)**	**$(159,066)**

As at December 31, 2011 *(restated)*	Proportionate Consolidation Method	Equity Method	Total
Revenues	$194,899	$204,453	$399,352
Expenses	131,305	134,066	265,371
	$ 63,594	$ 70,387	$133,981
Current assets	48,858	15,793	64,651
Property, plant and equipment	260,411	33,823	294,234
Intangible assets	16,819	55,169	71,988
Long-term investments and other assets	–	2	2
Current liabilities	(15,590)	(13,311)	(28,901)
Other long-term liabilities	(4,951)	(843)	(5,794)
Operating activities	60,807	43,260	104,067
Investing activities	(11,469)	(17,301)	(28,770)
Financing activities	$ (45,100)	$ (26,736)	$ (71,836)

10. SHORT-TERM DEBT

	December 31 2012	December 31 2011
		(restated)
Bank indebtedness	**$ 2,149**	$ 5,564
$50 million demand operating facility	**2,675**	–
US$100 million operating facility	**49,745**	–
$25 million operating facility	**12,369**	11,260
$20 million demand operating facility	**–**	–
$75 million unsecured revolving letter of credit facility	**–**	–
$125 million unsecured bilateral letter of credit facility	**–**	–
	$66,938	$16,824

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, 2012 was 3.0 percent (December 31, 2011 – 3.0 percent).

Revolving Operating Credit Facilities

As at December 31, 2012, the Corporation held a $50.0 million (December 31, 2011 – $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, 2012 were $0.02 million (December 31, 2011 – $0.02 million).

As at December 31, 2012, SEMCO held a US$100.0 million unsecured revolving operating credit facility with a Canadian chartered bank with a maturity date of August 30, 2014. Draws on the facility can be by way of U.S. base-rate loans, letters of credits and LIBOR loans. Letters of credit outstanding at December 31, 2012 were $0.2 million.

As at December 31, 2012, AltaGas held a $25.0 million (December 31, 2011 – $25.0 million) bank operating facility which is available for working capital purposes, has a term of 18 months and expires on November 22, 2013. The operating facility was acquired through the acquisition of PNG. Draws on the facility are by way of prime-rate advances, bankers' acceptance or letters of credits at the bank's prime rate or for a fee. Letters of credit outstanding at December 31, 2012 were $3.0 million (December 31, 2011 – $2.6 million).

As at December 31, 2012, the Utility Group held a $20 million (December 31, 2011 – $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 or bankers' acceptances and LIBOR loans. Letters of credit outstanding at December 31, 2012 were $3.4 million (December 31, 2011 – $3.4 million).

As at December 31, 2012, AltaGas held a $75.0 million (December 31, 2011 – $75.0 million) unsecured four-year extendible revolving letter of credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans or bankers' acceptances on letter of credit facility. Letters of credit outstanding at December 31, 2012 were $50.0 million (December 31, 2011 – $67.7 million).

As at December 31, 2012, AltaGas held a $125.0 million (December 31, 2011– $125.0 million) unsecured bilateral letter of credit facility. Draws on the facility can be by way of letters of credit under the facility. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draws made. Letters of credit outstanding at December 31, 2012 were $89.8 million (December 31, 2011 – $124.3 million).

11. LONG-TERM DEBT

	Maturity date	December 31, 2012	December 31, 2011
			(restated)
Credit facilities			
$35 million PNG 5 years revolver – 4.38 percent [1]	30-Jan-2015	$ 30,000	$ 20,000
$200 million Utility Group [2]	17-Nov-2015	131,342	30,962
$600 million Unsecured extendible revolving [2,3]	30-May-2016	227,345	8,000
US$300 million Unsecured [2]	02-Sep-2014	169,133	–
US$90 million CINGSA secured construction and term loan [4]	14-Nov-2015	77,105	–
Medium-term notes			
$100 million Senior unsecured – 5.07 percent	19-Jan-2012	–	100,000
$200 million Senior unsecured – 7.42 percent	29-Apr-2014	200,000	200,000
$100 million Senior unsecured – 6.94 percent	29-Jun-2016	100,000	100,000
$200 million Senior unsecured – 5.49 percent	27-Mar-2017	200,000	200,000
$175 million Senior unsecured – 4.60 percent	15-Jan-2018	175,000	175,000
$200 million Senior unsecured – 4.10 percent	24-Mar-2016	200,000	200,000
$200 million Senior unsecured – 4.55 percent	17-Jan-2019	200,000	200,000
$200 million Senior unsecured – 4.07 percent	01-Jun-2020	200,000	–
$350 million Senior unsecured – 3.72 percent	28-Sep-2021	350,000	–
US$5 million SEMCO unsecured – 7.03 percent	25-Nov-2013	4,923	–
US$300 million SEMCO Senior secured – 5.15 percent [5]	21-Apr-2020	298,470	–
Debenture notes			
PNG RoyNat Debenture – 3.72 percent [1]	15-Sep-2017	12,200	13,400
PNG 2018 Series Debenture – 8.75 percent [1]	15-Nov-2018	11,600	12,200
PNG 2024 CFI Debenture – 7.39 percent [6]	01-Nov-2024	8,353	8,775
PNG 2025 Series Debenture – 9.30 percent [1]	18-Jul-2025	15,500	16,000
PNG 2027 Series Debenture – 6.90 percent [1]	02-Dec-2027	16,500	17,000
Loan from Province of Nova Scotia [7]	31-Jul-2017	3,964	4,815
Capital lease obligations – 6.85 percent [8]	31-Aug-2014	–	4,567
SEMCO capital lease obligation – 3.50 percent	01-May-2040	445	–
Promissory notes	25-Oct-2015	2,866	3,839
Other long-term debt		642	5,702
		2,635,388	1,320,260
Less current portion		9,302	105,962
		$2,626,086	$1,214,298

1 *Collateral for the Secured Debenture consists of a specific first mortgage on substantially all of PNG's PPE and gas purchase and gas sales contracts and a first floating charge on other property, assets and undertakings.*

2 *Borrowings on the facilities can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facilities have fees and interest at rates relevant to the nature of the draw made.*

3 *The credit facility contains a $200 million accordion feature which allows AltaGas to increase the credit facility to an aggregate amount of $800 million.*

4 *Borrowings on the facility can be by way of LIBOR loans or alternative base rate loans. Borrowings on the facility have fees and interest at rates relevant to the nature of the draw made. The facility is non-recourse to the CINGSA subsidiary.*

5 *Collateral for the USD MTNs is certain SEMCO assets.*

6 *Collateral for the CFI Debenture consists of first fixed specific and floating charges and a security interest over all the assets and undertakings of McNair Creek, a first security interest over all the interests of PNG in partnership interests and shares in McNair Creek.*

7 *The loan is non-interest bearing and, if certain prescribed revenue targets are achieved, interest will immediately begin to accumulate on a prospective basis at a rate of 6 percent per annum. In July 2011, Heritage Gas elected to repay the loan in five equal installments beginning July 31, 2012. Heritage Gas may also elect to fully repay the loan at any time with no penalty.*

8 *The lease was terminated during first quarter 2012 and the leased assets were subsequently acquired by AltaGas.*

12. ASSET RETIREMENT OBLIGATIONS

	2012	2011
Balance, beginning of year	**$44,318**	$39,516
New obligations	**6,421**	910
Obligations settled	**(2,329)**	(851)
Revision in estimated cash flow	**(5,220)**	2,297
Accretion expense	**3,115**	2,446
Business acquisitions	**10,238**	–
Foreign exchange translation	**89**	–
Balance, end of year	**$56,632**	$44,318

The majority of the asset retirement obligations are associated with FG&P and extraction facilities in the Gas segment. In 2012 the Corporation recognized asset retirement obligations for the Northwest Projects.

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations at December 31, 2012 was $221.9 million (December 31, 2011 – $170.2 million).

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 2016 and 2164. No assets have been legally restricted for settlement of the estimated liability.

13. NORTHWEST TRANSMISSION LINE

In 2010, AltaGas entered into a 60-year CPI indexed EPA and other related agreements with BC Hydro for its 195 MW Forrest Kerr run-of-river hydroelectric project.

As at December 31, 2012, approximately $28.8 million of the total initial consideration of $90.0 million (recognized as intangible asset) is remaining to be paid to BC Hydro in support of the construction and operation of the Northwest Transmission Line. The amount of $28.8 million is recorded in "Accounts payable and accrued liabilities."

After commercial operation date, AltaGas shall make a series of 20 annual payments (annual considerations), the first of which shall be in the amount of approximately $4.9 million, and annually thereafter in the amount of approximately $9.8 million adjusted for inflation. Annual considerations have not been recognized in the statement of financial position.

14. INCOME TAXES

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 income tax statutory rates to income before tax as follows:

Year ended December 31	2012	2011
		(restated)
Income before income taxes – consolidated	$166,308	$112,995
Financial instruments – net	(22,057)	9,003
Income before financial instruments and income taxes	144,251	121,998
Income before income taxes – operating subsidiaries	144,251	121,998
Statutory income tax rate (%)	25.13	26.50
Expected taxes at statutory rates	36,250	32,329
Add (deduct) the tax effect of:		
Financial instruments	5,568	(2,596)
Rate adjustments to enacted Canadian rates	396	(1,109)
Higher effective foreign tax rates	197	–
Permanent differences between accounting and tax basis of assets and liabilities	2,190	487
Non-taxable portion of capital gains (losses) on disposition of assets and investments	22	319
Rate adjustment [1]	1,125	(6,861)
Tax on preferred shares	2,623	1,750
Other	984	660
Deferred income tax (recovery) on regulated assets	(5,617)	(4,725)
Prior year adjustment	2,312	11
	46,050	20,265
Income tax provision		
Current		
Canada	7,344	4,052
United States	1,629	–
	8,973	4,052
Deferred		
Canada	32,122	16,213
United States	4,955	–
	$ 37,077	$ 16,213
Effective income tax rate (%)	27.69	17.93

1 *During 2012 the enacted statutory provincial income tax rate for Ontario was increased to 11.5 percent from the previously enacted rate of 10 percent. During 2011 it was determined that deferred tax rate of 25 percent (previously 26 percent) more accurately reflected the enacted tax rates for the Corporation.*

In 2012, $96.2 million of deferred income tax liabilities were assumed on the acquisition of SEMCO. In 2011, $19.3 million of deferred income tax liabilities was assumed on the acquisition of PNG.

Deferred income taxes were composed of the following:

As at December 31	2012	2011
		(restated)
PPE and Intangible assets	**$440,907**	$278,479
Regulatory assets	**45,449**	20,576
Deferred financing	**(6,120)**	(3,041)
Partnerships	**–**	8,448
Deferred compensation	**195**	(3,658)
Financial instruments	**3,452**	(2,444)
Non-capital losses	**(93,370)**	(32,484)
Other	**761**	(42)
	$391,274	$265,834

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

As at December 31, 2012 the Corporation had tax-affected non-capital losses of approximately $93 million for tax purposes, which will be available to offset future taxable income. If not used, these losses will expire between 2013 and 2032.

Undistributed earnings of the Corporation's in the United States amounted to approximately $11 million at December 31, 2012. Those earnings are considered to be indefinitely re-invested; accordingly no provision for U.S. federal withholding taxes has been provided thereon. Upon repatriation of those earnings, in the form of dividends, the Corporation would be subject to U.S. withholding taxes.

Uncertain Tax Positions

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

On an annual basis, the Corporation and its subsidiaries file tax returns in Canada and various foreign jurisdictions. In Canada AltaGas' federal and provincial tax returns for the years 2006 to 2011 remain subject to examination by taxation authorities. In the United States both the federal and state tax returns filed for the years 2008 to 2011 remain subject to examination by the taxation authorities.

Management determined that the following provision was required for uncertainty on income taxes during the year:

Years ended December 31	2012	2011
		(restated)
Balance, beginning of year	**–**	–
Increases as a result of business combinations	**$ 3,675**	–
Increases as a result of positions taken during the year	**466**	–
Decreases due to expiration of statute of limitations	**(838)**	–
Balance, end of year	**$ 3,303**	–

15. REGULATORY ASSETS AND LIABILITIES

AltaGas accounts for certain transactions in accordance with ASC 980, Regulated Operations. AltaGas refers to this accounting guidance for regulated entities as "regulatory accounting". Under regulatory accounting, utilities are permitted to defer expenses and income as regulatory assets and liabilities, respectively, in the Consolidated Balance Sheets when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the Consolidated Statements of Income by a non-rate-regulated entity. These deferred regulatory assets and liabilities are included in the Consolidated Statements of Income in future periods when the amounts are reflected in customer rates. Management's assessment of the probability of recovery or pass-through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory agency orders, rules, and ratemaking conventions. The relevant regulatory bodies are the AUC, BCUC and NSUARB in Canada and MPSC and RCA in the United States.

If, for any reason, the Corporation ceases to meet the criteria for application of regulatory accounting for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be de-recognized from the Consolidated Balance Sheets and included in the Consolidated Statements of Income for the period in which the discontinuance of regulatory accounting occurs. Criteria that give rise to the discontinuance of regulatory accounting include (i) increasing competition that restricts the ability of the Corporation to charge prices sufficient to recover specific costs, and (ii) a significant change in the manner in which rates are set by regulatory agencies from cost-based regulation to another form of regulation. The Corporation's review of these criteria currently supports the continued application of regulatory accounting for utilities.

The following table summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets, as well as the remaining period, as of December 31, 2012, over which the Corporation expects to realize or settle the assets or liabilities:

	December 31, 2012	December 31, 2011	Recovery Period
		(restated)	
Regulatory assets – current			
Deferred cost of gas	$ 3,965	$ 5,141	Less than one year
Deferred property taxes	323	–	Less than one year
Other	56	–	Less than one year
	4,344	5,141	
Regulatory assets – non-current			
Deferred regulatory costs and rate stabilization adjustment mechanism	6,248	2,316	1-3 years
Pipeline rehabilitation costs	5,251	2,704	10 years
Future recovery of pension and other retirement benefits *(Note a)*	119,205	24,826	Various
Deferred environmental costs	19,742	–	1-10 years
Deferred loss on reacquired debt	3,508	–	4-7 years
Deferred depreciation and amortization *(Note b)*	12,808	9,180	
Deferred future income taxes *(Note c)*	63,588	41,128	Various
Revenue deficiency account *(Note d)*	44,508	45,117	
Other	405	–	1-3 years
	275,263	125,271	
Regulatory liabilities – current			
Deferred cost of gas	1,710	56	Less than one year
Deferred regulatory costs	261	353	Less than one year
Other	–	94	Less than one year
	1,971	503	
Regulatory liabilities – non-current			
Termination payment deferral *(Note e)*	1,862	3,454	
Option fees deferral *(Note f)*	3,033	3,021	
Future removal and site restoration costs *(Note g)*	98,283	20,211	Various
Insurance recovery of environmental costs	1,104	–	6 years
	$104,282	$26,686	

a. Certain utilities have recovered pension costs related to regulated operations in rates, and as such the Corporation has recorded a regulatory asset for the pension funding deficiency. Depending on the method utilized by the utility the recovery period can be either the expected service life of the employees or the benefit period for employees or a specific recovery period as approved by the respective regulator.

b. 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 fiscal periods from 2009 to 2011 inclusively. The NSUARB, in its most recent decision dated November 24, 2011, continued the order to suspend amortization for regulatory purposes for the fiscal periods from 2012 to 2013 inclusively, however amortization should resume for regulatory purposes in 2014 at 25 percent of authorized rates; 2015 at 50 percent of authorized rates; 2016 at 75 percent of authorized rates; and 2017 at 100 percent of authorized rates. As a result of this order, the Corporation recognizes a regulatory asset equal to the amortization that would have otherwise been included in rates. As at December 31, 2012, the Corporation has recorded a deferred regulatory asset of $12.8 million (2011 – $9.2 million) related to this decision. This amount is expected to be recovered over the remaining useful life of related assets commencing in 2014.

c. Remaining amortization period varies depending on the timing of underlying transactions.

d. Heritage Gas has an approval from the NSUARB to use a revenue deficiency account (RDA) until it is fully recovered, subject to a cap of $50 million, imposed in 2010, which may be increased subject to approval by the NSUARB. The RDA is the cumulative difference between the revenue requirements and the actual amounts billed to customers.

e. In 2010, West Fraser Timber Co. Ltd. (West Fraser) terminated its transportation service agreement with PNG related to its Kitimat, British Columbia linerboard mill. West Fraser continued to pay the monthly demand charge due under the transportation agreement until November 30, 2010 and then made a termination payment of approximately $5.0 million on December 1, 2010. The termination payment is being amortized over a period of 37 months, the remaining life of the agreement. The lost future revenues from the West Fraser contract are expected to be recoverable through standard rate applications to the BCUC.

f. In 2009, Merrill Lynch paid $2.5 million in option and extension fees to PNG to secure excess firm pipeline capacity. In 2010, further deposits totaling $2.0 million were paid to PNG and the agreement between PNG and Merrill Lynch was assigned and novated by Merrill Lynch to LNG Partners, LLC (LNG Partners). In 2011 and 2012, further deposits totaling $2.0 million and $1.0 million, respectively, were paid to PNG. Pursuant to the BCUC approved 2009, 2010 and 2011 negotiated settlement agreement, PNG has recorded these amounts as an interest bearing, non-rate base regulatory liability to be credited to cost-of-service in future years. The 2012 closing balance reflects total contributions of $7.5 million of which PNG has drawn down $4.5 million.

g. This amount and timing of draw down is dependent upon the cost of removal of underlying utility property, plant and equipment and the life of property, plant and equipment.

16. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

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

Fair Values of Financial Instruments

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

The following methods and assumptions were used to estimate the fair value of each significant class of financial instruments:

Cash, Cash Equivalents, Accounts Receivable, Accounts Payable, Short-term debt and Dividends Payable – the carrying amount approximates fair value because of the short maturity of these instruments.

Current portion of long-term debt and Long-term debt – the fair value of current portion of long-term debt and long-term debt have been estimated based on discounted future interest and principal payments using estimated interest rates.

Summary of Fair Values	**December 31 2012**	December 31 2011
Current portion of long-term debt		
Carrying amount	**$ 9,302**	$ 105,962
Fair value of current portion of long-term debt	**$ 10,243**	$ 103,997

Summary of Fair Values	**December 31 2012**	December 31 2011
		(restated)
Long-term debt excluding non-financial instruments		
Carrying amount	**$2,626,086**	$1,214,298
Fair value of long-term debt excluding non-financial instruments	**$2,800,759**	$1,255,562

Fair Value Hierarchy

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

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

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

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

December 31, 2012	Level 1	Level 2	Level 3	Total
Financial Assets				
Cash and cash equivalents	**$11,827**	**–**	**–**	**$ 11,827**
Risk management assets – current	**–**	**$ 47,788**	**–**	**$ 47,788**
Risk management assets – non-current	**–**	**$ 18,132**	**–**	**$ 18,132**
Long-term investments and other assets	**$ 7,715**	**–**	**–**	**$ 7,715**
Financial Liabilities				
Risk management liabilities – current	**–**	**$ 39,734**	**–**	**$ 39,734**
Risk management liabilities – non-current	**–**	**$ 10,526**	**–**	**$ 10,526**
Current portion of long-term debt	**–**	**$ 10,243**	**–**	**$ 10,243**
Long-term debt	**–**	**$2,800,759**	**–**	**$2,800,759**

December 31, 2011 *(restated)*				
Financial Assets				
Cash and cash equivalents	$ 2,875	–	–	$ 2,875
Risk management assets – current	–	$ 68,404	–	$ 68,404
Risk management assets – non-current	–	$ 21,642	–	$ 21,642
Long-term investments and other assets	$ 6,829	–	–	$ 6,829
Financial Liabilities				
Risk management liabilities – current	–	$ 72,973	–	$ 72,973
Risk management liabilities – non-current	–	$ 20,608	–	$ 20,608
Current portion of long-term debt	–	$ 103,997	–	$ 103,997
Long-term debt	–	$1,255,562	–	$1,255,562

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

Years ended December 31	2012	2011
		(restated)
Natural gas	$ (9,976)	$ 3,521
Storage optimization	296	(1,352)
NGL Frac Spread	15,940	(3,311)
Power	15,960	(8,784)
Heat rate	(578)	992
Interest rate swaps	7	(207)
Foreign exchange	16	138
Embedded derivative	392	–
	$22,057	$(9,003)

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

	Unrealized Losses	Tax Recovery	Year Ended December 31 2012	Unrealized Losses	Tax Recovery	Year Ended December 31 2011
						(restated)
Available-for-sale	$(6,631)	$844	$(5,787)	$(6,737)	$ 842	$(5,895)
Bond forward	(994)	–	(994)	(1,673)	–	(1,673)
NGL Frac Spread	–	–	–	(1,506)	376	(1,130)
OCI	$(7,625)	$844	$(6,781)	$(9,916)	$1,218	$(8,698)

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 2017. AltaGas had the following contracts outstanding:

December 31, 2012			Notional volume (GJ)		
Derivative Instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$2.56 to $9.85	1-58	113,661,098	–	$(5,244)
Commodity forward	$2.57 to $8.80	1-58	–	99,215,653	$ 7,028

December 31, 2011			Notional volume (GJ)		
Derivative Instruments	Fixed price (per GJ)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$2.33 to $9.85	1-48	116,826,997	–	$ 71,351
Commodity forward	$2.25 to $8.80	1-48	–	114,334,527	$(56,525)

AltaGas had the following commodity swaps outstanding related to the storage optimization activities (December 31, 2011 – none).

December 31, 2012			Notional volume (MMBTU)		
Derivative Instruments	Fixed price (per MMBTU)	Period (months)	Sales	Purchases	Fair value
Swaps	**$3.265 to $4.026**	**1-2**	**4,225,155**	**-**	**$(12,438)**
Swaps	**$3.317 to $3.506**	**1-2**	**-**	**4,225,155**	**$ 15,807**

NGL Frac Spread

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

December 31, 2012			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	**$1.2525 to $1.2824 US/gallon**	**1-12**	**20,958,000 gallons**	**–**	**$ 188**
Butane	**$1.51 to $1.7577 US/gallon**	**1-12**	**6,661,200 gallons**	**–**	**$ 5,077**
WTI	**$91.40 to $100.73 US/Bbl**	**1-12**	**72,300,661 gallons**	**–**	**$ (223)**
USD swaps	**$1.0232**	**1-12**	**–**	**$21,928,630**	**$ 521**
Natural gas	**$3.1950 to $4.0150/GJ**	**1-12**	**–**	**3,109,700 GJ**	**$(1,629)**

December 31, 2011			Notional volume		
Product	Fixed price	Period (months)	Sales	Purchases	Fair value
Propane	$1.0465 to $1.42 US/gallon	1-24	57,447,600 gallons	–	$ (911)
Butane	$1.4057 to $1.8475 US/gallon	1-24	18,232,200 gallons	–	$(2,473)
WTI	$90.36 to $104.60 US/Bbl	1-24	198,700 Bbls	–	$ (639)
USD swaps	$0.9767 to $1.0232	1-24	–	$82,961	$(2,056)
Natural gas	$2.91 to $4.30/GJ	1-24	–	8,527,700 GJ	$(5,225)

Power

Under the Sundance PPAs AltaGas has an obligation to buy power at agreed terms and prices to December 31, 2020. The Corporation sells the power to the Alberta Electric System Operator at market prices and uses swaps to fix the prices over time on a portion of the volumes. AltaGas' strategy is to mitigate the cash flow risk to Alberta power prices 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, 2012, AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following commodity forward contracts on electrical power outstanding:

December 31, 2012			Notional volume (MWh)		
Derivative Instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Commodity forward	**$43.94 to $94.1**	**1-60**	**1,780,422**	**–**	**$ 6,412**
Commodity forward	**$48.50 to $99.9**	**1-60**	**–**	**1,637,641**	**$(1,227)**

December 31, 2011			Notional volume (MWh)		
Derivative Instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Commodity forward	$52.75 to $68.75	1-42	209,531	–	$(3,012)
Commodity forward	$52.50	1-12	–	43,920	$ 1,081

AltaGas had the following commodity swaps outstanding:

December 31, 2012			Notional volume (MWh)		
Derivative Instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Swaps	**$64.00 to $77.00**	**1-12**	**412,560**	**–**	**$ 3,739**
Swaps	**$56.50**	**1-60**	**–**	**131,472**	**$ (470)**

December 31, 2011			Notional volume (MWh)		
Derivative Instruments	Fixed price (per MWh)	Period (months)	Sales	Purchases	Fair value
Swaps	$60.00 to $137.95	1-24	1,159,200	–	$(8,317)
Swaps	$56.50 to $67.25	1-72	–	166,608	$ 2,705

AltaGas had the following heat rate hedges outstanding:

December 31, 2012			Notional volume (GJ or MWh)		
Derivative Instruments	Fixed price (perGJ or MWh)	Period (months)	Sales	Purchases	Fair value
Natural gas	**$2.975**	**1**	**–**	**124,000**	**$ (1)**
Power	**$91.9 to $95.35**	**1**	**12,400**	**–**	**$ 79**

December 31, 2011			Notional volume (GJ or MWh)		
Derivative Instruments	Fixed price (perGJ or MWh)	Period (months)	Sales	Purchases	Fair value
Natural gas	$2.895 to $3.1188	1 to 2	–	193,600	$ (80)
Power	$149.45 to $183.75	1 to 2	18,150	–	$736

Interest Rate Risk Management

To hedge against the effects of future interest rate movements, AltaGas, from time to time, enters into interest rate swap agreements to fix the interest rate on a portion of its bankers' acceptances issued under credit facilities.

AltaGas had no interest rate swaps outstanding as at December 31, 2012.

December 31, 2011	Weighted average interest rate	Period (months)	Notional quantity	Fair value
Swaps	1.350 percent	1-3	$40,000	$12

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.

AltaGas had no contracts outstanding as at December 31, 2012.

December 31, 2011	Fixed Price	Period (months)	Notional quantity	Fair value
Swaps (USD)	$0.9527 to $1.0597	1-23	$16,726	$415

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.

Sensitivity Analysis

The sensitivity analysis is estimated based on the notional volumes of each commodity contract and equity security 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, 2012:

Factor Share	Increase or decrease [1]	Increase or decrease in net income	Increase or decrease in OCI
Alberta electricity average pool prices	$1/MWh	$ 318	–
Natural gas spot price (AECO)	$0.50/GJ	$ 607	–
NGL frac spread:			
Propane	$1/Bbl	$ 498	–
Butane	$1/Bbl	$ 158	–
WTI	$1/Bbl	$ 35	–
Natural gas to replace heat value of NGL	$0.50/GJ	$1,603	–
Change in Canadian dollar per U.S. dollar exchange rate	1 percent	$ 408	–
Equity risk	1 percent	$ 33	$31

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, 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. As at December 31, 2012, AltaGas had no concentration of credit risk with a single counterparty.

Accounts Receivable Past Due or Impaired

AltaGas had the following past due or impaired receivables:

			Receivables by period and not impaired			
Accounts receivable	December 31, 2012	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$370,993	$3,595	$348,149	$8,747	$8,801	$1,701
Other	15,212	–	13,750	–	–	1,462
Allowance for credit losses	(3,595)	(3,595)	–	–	–	–
	$382,610	–	$361,899	$8,747	$8,801	$3,163

Allowance for credit losses	As at December 31, 2012
Allowance for credit losses, beginning of year	**$2,099**
Business acquisition (note 3)	**1,594**
Foreign exchange translation	**(14)**
New allowance	**255**
Allowance applied to uncollectible customer accounts	**(339)**
Allowance for credit losses, end of year	**$3,595**

			Receivables by period and not impaired			
Accounts receivable	December 31, 2011 *(restated)*	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$228,413	$2,099	$217,089	$5,924	$1,471	$1,830
Other receivable	8,220	-	6,047	-	-	2,173
Allowance for credit losses	(2,099)	(2,099)	-	-	-	-
	$234,534	-	$223,136	$5,924	$1,471	$4,003

Allowance for credit losses	As at December 31, 2011
Allowance for credit losses, beginning of year	$1,325
Business acquisition	713
New allowance	224
Allowance applied to uncollectible customer accounts	(163)
Allowance for credit losses, end of year	$2,099

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.

AltaGas had the following contractual maturities with respect to non-derivative financial liabilities:

		Payments Due by period			
As at December 31, 2012	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	**$ 370,011**	**$370,011**	**–**	**–**	**–**
Dividends payable	**12,640**	**12,640**	**–**	**–**	**–**
Short-term debt	**66,938**	**66,938**	**–**	**–**	**–**
Current portion of long-term debt	**9,302**	**9,302**	**–**	**–**	**–**
Long-term debt	**2,626,086**	**–**	**620,400**	**741,732**	**1,263,954**
	$3,084,977	**$458,891**	**$620,400**	**$741,732**	**$1,263,954**

		Payments Due by period			
As at December 31, 2011 *(restated)*	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Accounts payable and accrued liabilities	$ 314,422	$314,422	–	–	–
Dividends payable	10,264	10,264	–	–	–
Short-term debt	16,824	16,824	–	–	–
Current portion of long-term debt	105,962	105,962	–	–	–
Long-term debt	1,214,298	–	284,705	304,918	624,675
	$1,661,770	$447,472	$284,705	$304,918	$ 624,675

17. SHAREHOLDERS' EQUITY

Authorization

AltaGas is authorized to issue an unlimited number of voting common shares. AltaGas is also authorized to issue preferred shares not to exceed 50 percent of the voting rights attached to the issued and outstanding common shares.

Preferred Shares

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

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

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

On June 6, 2012, AltaGas issued 8,000,000 five-year rate reset preferred shares, Series C (the Series C Preferred Shares), at a price of US$25 per Series C Preferred Share, for aggregate gross proceeds of US$200 million.

Holders of the Series C Preferred Shares are entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding September 30, 2017 at an annual rate of US$1.10 per share, payable quarterly, as and when declared by the Board of Directors of AltaGas. The first dividend payments of $0.3473 per Series C Preferred Share will be payable on October 1, 2012. The dividend rate will reset on September 30, 2017, and every five years thereafter, equal to the sum of the U.S. Government Bond Yield on the applicable rate calculation date plus 3.58 percent. The Series C Preferred Shares shall not be redeemable prior to September 30, 2017. In every fifth year thereafter, on September 30 AltaGas may, at its option, redeem for cash all or any part of the outstanding Series C shares by payment of US$25 per Series C share plus accrued and unpaid dividends.

Holders of Series C Preferred Shares have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, Series D (the Series D Preferred Shares), subject to certain conditions, on September 30, 2017, and on September 30 of every fifth year thereafter. Holders of Series D Preferred Shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the floating quarterly dividend rate by US$25 per share and multiplying that product by a fraction, the numerator of which is the actual of days in such quarterly floating rate period and the denominator of which is 365 or 366, depending upon the actual number of days in the applicable year. The floating quarterly dividend rate will be the annual rate of interest equal to the sum of the Treasury Bill rate on the applicable rate calculation date plus 3.58 percent.

Common Shares Issued and Outstanding	Number of shares	Amount
January 1, 2011	82,526,399	$1,023,033
Shares issued for cash on exercise of options	398,920	7,181
Shares issued under DRIP	1,412,555	34,681
Shares issued on public offering	4,910,500	139,374
December 31, 2011	89,248,374	$1,204,269
Shares issued for cash on exercise of options	779,969	16,197
Shares issued under DRIP	1,393,541	41,071
Shares issued on conversion of subscription receipts	13,915,000	378,358
Issued and outstanding at December 31, 2012	105,336,884	$1,639,895

Preferred Shares Series A Issued and Outstanding	Number of shares	Amount
January 1, 2011	8,000,000	$ 194,126
December 31, 2011	8,000,000	194,126
Issued and outstanding at December 31, 2012	8,000,000	$ 194,126

Preferred Shares Series C Issued and Outstanding	Number of shares	Amount
January 1, 2011	–	–
December 31, 2011	–	–
Shares issued on public offering	8,000,000	200,626
Issued and outstanding at December 31, 2012	8,000,000	$ 200,626

Weighted Average Shares Outstanding	2012	2011
Number of shares – basic	94,986,369	84,041,524
Dilutive equity instruments [1]	1,324,669	1,164,964
Number of shares – diluted	96,311,038	85,206,488

1 Includes all options that have a strike price lower than the market share price of AltaGas' common shares at December 31, 2012 and 2011, respectively.

For year ended December 31, 2012, 668,516 options were excluded from the computation of diluted earnings per share because their effects were not dilutive (year ended December 31, 2011 – 1,481,637 options).

Subscription Receipts

On February 22, 2012, AltaGas closed approximately $403 million in gross proceeds which were held in trust in consideration of a subscription receipts offering of 13,915,000 common shares. The subscription receipts offering represented the holder's right to receive one common share of the issuer contingent upon acquisition close. On August 30, 2012, each holder of a subscription receipt received one common share for each subscription receipt held, without payment of additional consideration or further action, plus an amount per common share equal to the amount per common share of cash dividends declared by AltaGas on the common shares to holders of record on the dates during the period from and including the subscription closing date up to but not including the transaction closing date, net of any applicable withholding taxes.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at December 31, 2012, 4,687,228 shares were reserved for issuance under the plan. As at December 31, 2012, options granted under the plan generally have a term of 10 years until expiry and vest no longer than over a four-year period.

As at December 31, 2012, outstanding options were exercisable at various dates within the next ten years. As at December 31, 2012, the unexpensed fair value of share option compensation cost associated with future periods was $7.9 million (December 31, 2011 – $5.8 million).

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

	Options outstanding			
	2012		2011	
	Number of options	Exercise price [1]	Number of options	Exercise price [1]
Share options outstanding, beginning of year	**5,337,705**	**$20.37**	4,858,500	$20.27
Granted	**1,544,500**	**31.15**	1,154,750	29.23
Exercised	**(781,220)**	**19.93**	(397,670)	17.66
Forfeited	**(254,525)**	**22.17**	(277,875)	21.20
Share options outstanding, end of year	**5,846,460**	**$25.01**	5,337,705	$22.37
Share options exercisable, end of year	**2,720,298**	**$21.66**	2,425,185	$21.28

1 *Weighted average.*

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

	Options outstanding			Options exercisable	
	Number outstanding	Weighted Average Exercise price	Weighted Average Remaining contractual life	Number exercisable	Exercise price
$7.25 to $15.25	467,935	$14.25	5.93	467,529	$14.25
$15.26 to $25.08	2,319,075	20.51	7.04	1,496,350	20.61
$25.09 to $34.54	3,059,450	30.07	8.47	756,419	28.33
	5,846,460	$25.01	7.70	2,720,298	$21.66

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

Years ended December 31	**2012**	2011
Risk-free interest rate *(%)*	**2.55**	2.96
Expected life *(years)*	**10**	10
Expected volatility (%)	**24.54**	24.73
Annual dividend per share ($)	**1.44**	1.33

In 2004, AltaGas implemented an equity-based compensation plan, which awards phantom shares to certain employees. Beginning in 2008, all employees were eligible to receive phantom shares. The phantom shares are valued based on dividends declared and the trading price of the Corporation's common shares. The shares vest on a graded vesting schedule over three years. For the year ended December 31, 2012, the compensation expense recorded was $5.5 million (2011 – $7.8 million). As at December 31, 2012, the unexpensed fair value of equity-based compensation costs associated with future periods was $8.8 million (December 31, 2011 – $14.4 million).

18. NET INCOME APPLICABLE TO COMMON SHARES

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

Year ended December 31	2012	2011
		(restated)
Numerator:		
Net income applicable to controlling interests	**$116,769**	$92,730
Less: Preferred share dividends	**14,922**	10,000
Net income applicable to common shares	**$101,847**	$82,730
Denominator:		
Weighted average number of common shares outstanding	**94,986**	84,042
Dilutive equity instruments [1]	**1,325**	1,165
Weighted average number of common shares outstanding – diluted	**96,311**	85,207
Basic net income applicable per common share	**$ 1.07**	$ 0.98
Diluted net income applicable per common share	**$ 1.06**	$ 0.97

1 Includes all options that have a strike price lower than the market share price of AltaGas' common shares at December 31, 2012 and 2011, respectively.

19. COMMITMENTS

AltaGas has long-term natural gas purchase arrangements, service agreements, power purchase agreements, and operating leases for office space, office equipment and automobile equipment, all of which are transacted at market prices and in the normal course of business.

Future payments of these commitments at December 31, 2012 are estimated as follows:

	2013	2014	2015	2016	2017	2018 and beyond	Total
Gas purchase	$ 178,114	$122,539	$82,125	$ 57,521	$38,633	$22,849	$501,781
Service agreement	776	776	1,472	1,472	1,472	5,887	11,855
Storage services	3,344	3,366	3,389	3,412	3,436	43,179	60,126
Capital projects	131,196	35,473	2,319	–	–	–	168,988
Leases	18,570	7,420	6,365	4,959	4,165	607	42,086
	$332,000	$ 169,574	$95,670	$67,364	$47,706	$72,522	$784,836

AltaGas enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers for its U.S. utilities. These contracts, which have expiration dates that range from 2013 to 2019, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $11.9 million over the next 9 years, of which $6.0 million is payable in the next five years.

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

In 2010, AltaGas entered into a 60-year CPI indexed EPA with BC Hydro for the Northwest Projects. At December 31, 2012, AltaGas is committed to pay approximately $162.1 million for construction work related to these projects which are expected to be in service in 2014 and 2015. Other commitments for capital projects of $6.9 million relate to Gas projects completed in 2012 with payments due in 2013.

20. PENSION PLANS AND RETIREE BENEFITS

Defined Contribution Plan

AltaGas has a defined contribution (DC) pension plan for substantially all employees who are not members of defined benefit plans. The net pension expense recorded for the DC pension plan was $2.5 million for the year ended December 31, 2012 (2011 – $2.5 million).

Defined Benefit Plans

Effective August 25, 2004, the liability for a defined benefit, non-contributory pension plan in respect of nine Corporation 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 2012 and 2011 were made in accordance with an actuarial valuation for funding purposes as at September 30, 2008 based on a report dated April 29, 2009.

As at December 31, 2012, the accrued benefit obligation of the Corporation for this plan was $2.8 million (December 31, 2011 – $2.0 million). As at December 31, 2012, the plan had an accrued benefit liability recognized in the Consolidated Financial Statements of $0.3 million (December 31, 2011 – $0.2 million of accrued benefit asset).

In 2008, the Corporation assumed two defined benefit pension plans with the acquisition of Taylor. These plans are in relation to the unionized employees at Younger and certain employees at Harmattan. As at December 31, 2012, the accrued benefit obligation of the Corporation for these plans was $16.1 million (December 31, 2011 – $11.5 million). As at December 31, 2012, these plans had an accrued benefit liability recognized in the Consolidated Financial Statements of $5.9 million (December 31, 2011 – $2.3 million).

In 2009, the Corporation assumed two defined benefit non-contributory pension plans in the acquisition of Utility Group. The plans are in relation to substantially all full-time employees of AUI. As at December 31, 2012, the accrued benefit obligation of the Corporation for these plans was $35.4 million (December 31, 2011 – $28.0 million). As at December 31, 2012, the plans had accrued benefit liability recognized in the Consolidated Financial Statements of $7.7 million (December 31, 2011 – $6.5 million).

In 2011, the Corporation assumed two defined benefit pension plans with PNG's acquisition. These plans are in relation to PNG employees. As at December 31, 2012, the accrued benefit obligation of these plans was $39.2 million (December 31, 2011 – $32.3 million). As at December 31, 2012, these plans had an accrued benefit liability of $13.1 million (December 31, 2011 – $8.5 million).

On August 30, 2012, the Corporation assumed four defined benefit pension plans with SEMCO's acquisition. Two of these plans are in relation to SEMCO Energy's unionized employees and one plan is in relation to SEMCO Energy's salaried and hourly employees. Also SEMCO Energy participates in a multi-employer plan that covers 5 unionized employees in a non-regulated business. As at December 31, 2012, the accrued benefit obligation of the Corporation for these plans was $173.8 million. As at December 31, 2012, these plans had an accrued benefit liability of $54.8 million.

For the year ended December 31, 2012, the net pension cost for all defined benefit plans was $7.6 million (2011 – $2.5 million).

Supplemental Executive Retirement Plan (SERP)

Effective July 1, 2005, the Corporation 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, the Corporation assumed the liability recorded for the SERP held by Utility Group.

As at December 31, 2012, the accrued benefit obligation of the Corporation for this plan was $15.4 million (December 31, 2011 – $11.9 million). As at December 31, 2012, the plan had an accrued benefit liability recognized in the financial statements of $15.1 million (December 31, 2011 – $11.5 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.

On August 30, 2012, the Corporation assumed a SERP with the SEMCO acquisition, which is an unfunded defined benefit pension plan. As at December 31, 2012, the accrued benefit liability of the Corporation for this plan was $7.8 million.

For the year ended December 31, 2012, the net pension expense related to the SERP was $2.1 million (2011 – $2.3 million).

Post-Retirement Benefits

In 2008 the Corporation 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. As at December 31, 2012, the accrued benefit liability of the Corporation for this plan was $1.6 million (December 31, 2011 – $1.1 million).

In 2009 the Corporation 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.

In 2011 the Corporation assumed a post-retirement benefit plan for certain employees of PNG providing benefits such as health and life insurance. As at December 31, 2012, the accrued benefit obligation of this plan was $9.3 million (December 31, 2011 – $6.8 million). At December 31, 2012, this plan had an accrued benefit liability of $7.0 million (December 31, 2011 – $5.1 million).

On August 30, 2012, the Corporation assumed three post-retirement benefit plans with the SEMCO acquisition. Two of these plans are for SEMCO Energy's non-unionized employees and the third is for SEMCO Gas' unionized employees. These plans provide certain medical and prescription drug benefits to eligible retired employees, their spouses and covered dependents. Benefits are based on a combination of the retiree's age and years of service at retirement. SEMCO Energy accounts for retiree medical benefits with full accrual of costs during the years that the employee renders service to SEMCO Energy until the date of full eligibility. As at December 31, 2012, the accrued benefit obligation of the Corporation for these plans was $53.1 million. As at December 31, 2012, these plans had an accrued benefit liability of $12.9 million.

For the year ended December 31, 2012, the net benefit cost for these plans was $1.1 million (2011 – $0.3 million).

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

	Defined Benefit 2012	Post-Retirement Benefits 2012	Defined Benefit 2011 (restated)	Post-Retirement Benefits 2011 (restated)
Accrued benefit obligation				
Balance, beginning of year	$ 85,631	$ 10,064	$ 48,016	$ 2,946
Assumed through acquisition [1]	180,640	55,099	32,276	6,799
Transfer of obligations	220	–	–	–
Actuarial loss	15,175	1,872	1,345	60
Current service cost	6,571	750	3,540	152
Member contributions	22	–	–	–
Interest cost	6,918	1,273	2,853	176
Benefits paid	(6,376)	(828)	(2,399)	(69)
Plan amendments	–	(1,946)	–	–
Foreign exchange translation	2,057	627	–	–
Balance, end of year	290,858	66,911	85,631	10,064
Plan assets				
Fair value, beginning of year	56,924	1,716	33,687	–
Assumed through acquisition [1]	111,616	37,840	23,762	1,716
Transfer of assets	220	–	–	–
Actual return on plan assets	10,504	56	(1,800)	–
Employer contributions	11,918	2,423	3,906	69
Member contributions	128	382	102	–
Benefits paid	(6,376)	(265)	(2,399)	(69)
Actual plan expenses	–	–	(334)	–
Foreign exchange translation	1,271	431	–	–
Fair value, end of year	186,205	42,583	56,924	1,716
Accrued benefit liability	$(104,653)	$(24,328)	$(28,707)	$(8,348)

1 Includes the plans acquired in the acquisition of PNG on December 20, 2011 and SEMCO on August 30, 2012.

The following amounts were included in the Consolidated Balance Sheets:

	Defined Benefit 2012	Post-Retirement Benefits 2012	Defined Benefit 2011 (restated)	Post-Retirement Benefits 2011 (restated)
Other current liabilities	2,077	–	41	–
Future employee obligations	102,576	24,328	28,666	8,348
	104,653	24,328	28,707	8,348

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

	Defined Benefit 2012	**Post-Retirement Benefits 2012**	Defined Benefit 2011 (restated)	Post-Retirement Benefits 2011 (restated)
Amounts included in Accumulated Other Comprehensive Income (Loss)				
Transitional obligation	**$(2,221)**	**$ (48)**	$ (365)	$ (48)
Amortization actuarial loss	**214**	**7**	–	–
Past service cost	**77**	**–**	(893)	–
Net actuarial gain (loss)	**(11,212)**	**(622)**	(3,136)	251
Total accumulated other comprehensive income (loss) on a pre-tax basis	**(13,142)**	**(663)**	(4,394)	203
Increase (decrease) by the amount included in deferred tax liabilities	**3,392**	**166**	1,098	(51)
Net amount in accumulated other comprehensive income (loss) after-tax	**$(9,750)**	**$ (497)**	$(3,296)	$ 152

Amounts to be amortized in the next fiscal year	Defined Benefit	Post-Retirement Benefits
Actuarial losses	$(6,182)	$(784)
Past service gains (losses)	(125)	227
Total	$(6,307)	$(557)

Benefit cost components	**Defined Benefit 2012**	**Post-Retirement Benefits 2012**	Defined Benefit 2011 (restated)	Post-Retirement Benefits 2011 (restated)
Net benefit plan expense for the year:				
Current service cost and expenses	**$ 6,447**	**$ 746**	$ 3,813	$ 152
Interest cost	**6,891**	**1,265**	2,853	176
Actual return on plan assets	**(6,067)**	**(999)**	(2,047)	–
Actuarial loss on accrued benefit obligation	**2,061**	**121**	140	(8)
Costs arising in the year	**$ 9,332**	**$1,133**	$ 4,759	$ 320

The objective of the Corporation's investment policy is to maximize long-term total return while protecting the capital value of the Fund from major market fluctuations through diversification and selection of investments.

The objective for Fund returns, over three to five year periods, is the sum of two components – a passive component, which is the benchmark index market returns for the asset mix in effect, plus the added value expected from active management. It is the Corporation's belief that the potential additional returns justify the additional risk associated with active management. The risk inherent in the investment strategy over a market cycle (a three to five-year period) is two-fold. There is a risk that the market returns, as measured by the benchmark returns, will not be in line with expectations. The other risk is that the expected added value of active management over passive management will not be realized over the time period prescribed in each Fund Manager's mandate. There is also the risk of annual volatility in returns which means that in any one year the actual return may be very different from the expected return.

Cash and money market investments may be held from time to time as short-term investment decisions at the discretion of the Fund Manager(s) within the constraints prescribed by their mandate(s).

The Corporation has set an overall objective to have a target asset mix of 45 percent to 55 percent of fixed income assets. This objective has taken into account the nature of the liabilities and the risk-reward tolerance of the Corporation.

In meeting the above overall objective, the Corporation has set an allocation of the Fund to various Pooled Funds, by asset class, as follows:

Component Asset Classes	Percentage of Fund at Market Value Target Allocation (%)
Canadian Bond Pooled Fund	35
Canadian Mortgage Pooled Fund	10
Fixed Income	45
Canadian Equity	18
Canadian Equity (Dividend)	13
U.S. Equity	9
International Equity	9
Equity	49
Other- Real Estate	6

The target asset allocation for the U.S. plans is 67 percent equities and 33 percent debt instruments.

The collective investment mixes for the plans are as follows as at December 31, 2012:

	Fair value	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	$ 4,271	$ 4,271	–	1.87
Canadian Equities	23,553	23,553	–	10.29
Foreign Equities	116,719	116,719	–	51.02
Fixed Income	80,711	80,711	–	35.28
Real Estate	3,534	–	3,534	1.54
	$228,788	$225,254	$3,534	100.00

	Defined Benefit 2012	**Post-Retirement Benefits 2012**	Defined Benefit 2011	Post-Retirement Benefits 2011
Significant actuarial assumptions used as at December 31				
Discount rate (%)	**3.20-4.40**	**3.95-4.40**	5.10-5.80	5.30-5.80
Expected long-term rate of return on plan assets (%)	**0.00-8.00**	**0.00-8.00**	0.00-7.00	0.00-6.25
Rate of compensation increase (%)	**0.00-4.00**	**0.00-4.00**	0.00-6.00	0.00-4.00
Average remaining service life of active employees (years)	**12.3**	**12.4**	15.3	13.2

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 rates used to measure the expected cost of benefits range between 4 and 10 percent and the ultimate trend rate between 4 and 5 percent, which is expected to be achieved by 2027.

The 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 2012:

	Increase	Decrease
Service and interest costs	$ 899	$ (684)
Accrued benefit obligation	$13,161	$(10,277)

The following table shows the expected cash flows for defined benefit pension and other post-retirement plans:

	Defined Benefit	Post-Retirement Benefits
Expected employer contributions:		
2013	$21,593	$ 1,823
Expected benefit payments:		
2013	$10,077	$ 1,846
2014	$ 9,858	$ 1,980
2015	$10,772	$ 2,156
2016	$12,326	$ 2,310
2017	$12,373	$ 2,507
2018 – 2022	$77,834	$ 15,132

21. RELATED PARTY TRANSACTIONS

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

22. SUBSEQUENT EVENT

On January 28, 2013, AltaGas announced that the Corporation has signed an agreement with Idemitsu Kosan Co., Ltd. (Idemitsu) to form the AltaGas Idemitsu Joint Venture Limited Partnership (AltaGas Idemitsu LP). AltaGas Idemitsu LP plans to pursue opportunities involving exports of Liquefied Petroleum Gas and Liquefied Natural Gas from Canada to Asia. AltaGas and Idemitsu will each own 50 percent interest in AltaGas Idemitsu LP.

23. SEGMENTED INFORMATION

AltaGas owns and operates a portfolio of assets and services used to move energy from the source to the end-user. The following describes the Corporation's four reporting segments:

Gas	• NGL processing and extraction plants; • transmission pipelines to transport natural gas and NGL; • natural gas gathering lines and field processing facilities; • energy consulting and purchase and sale of natural gas and electricity; and • natural gas storage facilities.
Power	• coal-fired, wind, biomass and run-of-river power output under power purchase arrangements; • gas-fired power plants; and • sale of power to commercial and industrial users in Alberta.
Utilities	• rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and • rate-regulated natural gas storage in Michigan and Alaska.
Corporate	• the cost of providing corporate services, financing and general corporate overhead, investments in public and private entities, corporate assets, financing other segments 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, 2012	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$ 908,022	$ 216,138	$ 437,638	$ 580	$(134,175)	$1,428,203
Unrealized gain on risk management	–	–	–	22,057	–	22,057
Cost of sales	(586,408)	(172,230)	(225,819)	–	132,144	(852,313)
Operating and administrative	(168,456)	(18,075)	(104,542)	(34,202)	2,031	(323,244)
Accretion of asset retirement obligations	(3,010)	(84)	(21)	–	–	(3,115)
Depreciation, depletion and amortization	(57,177)	(13,975)	(27,457)	(3,519)	–	(102,128)
Income from equity investments	622	65,116	859	–	–	66,597
Foreign exchange loss	–	–	–	(8,512)	–	(8,512)
Interest expense	–	–	–	(61,237)	–	(61,237)
Income (loss) before income taxes	$ 93,593	$ 76,890	$ 80,658	$ (84,833)	–	$ 166,308
Net additions (reductions) to:						
Property, plant and equipment [1]	$ 362,945	$ 302,662	$ 866,236	$ 254	–	$1,532,097
Intangible assets	$ (81)	$ 613	$ 12,020	$ (278)	–	$ 12,274
Long-term investment and other assets	$ (4,518)	$ 34,552	$ 26,477	$ 3,927	–	$ 60,438
As at December 31, 2012:						
Goodwill	$ 161,401	–	$ 553,501	–	–	$ 714,902
Segmented assets	$2,196,540	$1,050,180	$2,541,500	$123,720	–	$5,911,940

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

Year ended December 31, 2011 *(restated)*	Gas	Power	Utilities	Corporate	Intersegment Elimination	Total
Revenue	$1,085,027	$168,040	$161,022	$ (9,436)	$(125,057)	$1,279,596
Unrealized loss on risk management	–	–	–	(9,003)	–	(9,003)
Cost of sales	(747,713)	(128,858)	(79,441)	–	123,168	(832,844)
Operating and administrative	(175,898)	(16,670)	(46,858)	(27,352)	1,889	(264,889)
Accretion of asset retirement obligations	(2,384)	(48)	(14)	–	–	(2,446)
Depreciation, depletion and amortization	(54,403)	(10,267)	(10,844)	(4,171)	–	(79,685)
Income from equity investments	613	74,455	288	–	–	75,356
Foreign exchange loss	–	–	–	(383)	–	(383)
Interest expense	–	–	–	(52,707)	–	(52,707)
Income (loss) before income taxes	$ 105,242	$ 86,652	$ 24,153	$(103,052)	–	$ 112,995
Net additions to:						
Property, plant and equipment [1]	$ 255,826	$166,697	$211,543	$ 8,487	–	$ 642,553
Intangible assets	$ 5,278	$ 91,285	$ 423	$ 1,417	–	$ 98,403
Long-term investment and other assets	$ (296)	$ (457)	$ 281	$ (15,527)	–	$ (15,999)
As at December 31, 2011:						
Goodwill	$ 161,401	–	$119,722	–	–	$ 281,123
Segmented assets	$1,888,117	$693,948	$843,023	$ 131,138	–	$3,556,226

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

Geographic Information

Year ended December 31	**2012**	2011
Revenue [1]		*(restated)*
Canada	**$1,207,426**	$1,288,996
United States	**220,197**	36
Total	**$1,427,623**	$1,289,032

As at December 31	**2012**	2011
Property, plant and equipment		*(restated)*
Canada	**$3,083,197**	$2,461,582
United States	**865,969**	24,468
Total	**$3,949,166**	$2,486,050

1 *Operating revenue from external customers.*

24. US GAAP TRANSITION

Adoption of US GAAP

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

On September 10, 2010, the AcSB amended the introduction to Part I of the CICA Handbook Accounting to permit, but not to require qualifying entities with Rate-Regulated Activities (RRA) to adopt IFRS for the first time no later than interim and annual financial statements relating to annual periods beginning on or after January 1, 2012, thereby providing a one year deferral. The Canadian Securities Administrators provided for a similar one year deferral pursuant to National Instrument 52-107 "Acceptable Accounting Principles and Auditing Standards" (NI 52-107).

In September 2012, AcSB extended the deferral option of the mandatory changeover for entities with rate-regulated activity by one year to January 1, 2014.

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

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

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

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

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

In addition, US GAAP requires certain disclosures of financial information, significant to the Corporation, that were not required under Canadian GAAP. This information, which is as at December 31, 2011, is presented in Section II "Additional disclosures required under US GAAP".

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

Certain comparative figures for the adoption of US GAAP have been reclassified from those previously reported.

Section I – US GAAP Differences

The following table summarizes the change in total assets:

	Notes	January 1, 2011	December 31, 2011
Total assets – Canadian GAAP		$2,752,538	$3,542,420
Business combinations	A	(2,757)	(2,757)
Accounting for joint ventures	B	(16,394)	(12,843)
Pension and other post-retirement benefits	C	1,187	15,353
Natural gas held in storage	D	(903)	1,228
Debt issuance costs	F	9,470	12,825
Total assets – US GAAP		$ 2,743,141	$3,556,226

The following table summarizes the change in total liabilities:

	Notes	January 1, 2011	December 31, 2011
Total liabilities – Canadian GAAP		$ 1,541,507	$2,180,280
Business combinations	A	(5,971)	(5,971)
Accounting for joint ventures	B	(16,394)	(12,843)
Pension and other post-retirement benefits	C	4,618	19,844
Natural gas held in storage	D	(255)	278
Debt issuance costs	F	9,470	12,825
Income tax on preferred share dividends	G	275	1,025
Total liabilities – US GAAP		$1,533,250	$2,195,438

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

	Year ended December 31 2011
Net income applicable to common shares – Canadian GAAP	$83,604
C. Pension and other post-retirement benefits	392
D. Natural gas held in storage	1,598
E. De-designation of cash flow hedges	(2,114)
G. Income tax on preferred share dividends	(750)
Total transition adjustments	(874)
Net income applicable to common shares – US GAAP	$82,730
Net income applicable to common shares – basic per share – Canadian GAAP	$ 0.99
Effect of US GAAP transition	(0.01)
Net income applicable to common shares – basic per share – US GAAP	$ 0.98

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

As at January 1, 2011	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets				
Cash and cash equivalents	B	$ 2,109	$ (1,086)	$ 1,023
Accounts receivable	B	225,217	(17,635)	207,582
Inventory	D	13,106	(903)	12,203
Restricted cash holdings from customers		17,624	–	17,624
Regulatory assets		2	–	2
Risk management assets		41,226	–	41,226
Prepaid expense and other current assets	B, C & F	5,587	107	5,694
		304,871	(19,517)	285,354
Property, plant and equipment	A, B	1,976,538	(53,006)	1,923,532
Intangible assets	B	139,942	(59,919)	80,023
Goodwill	A & B	199,497	23,105	222,602
Regulatory assets	C	76,515	2,908	79,423
Risk management assets		22,587	–	22,587
Long-term investments and other assets	C & F	32,588	5,812	38,400
Investments accounted for by equity method	B	–	91,220	91,220
		$2,752,538	$ (9,397)	$2,743,141
Liabilities And Shareholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	B	$ 229,618	$(16,245)	$ 213,373
Dividends payable		9,078	–	9,078
Short-term debt		9,478	–	9,478
Current portion of long-term debt		1,508	–	1,508
Customer deposits		21,432	–	21,432
Regulatory liabilities		1,494	–	1,494
Risk management liabilities		39,209	–	39,209
Other current liabilities	B & C	12,302	(52)	12,250
		324,119	(16,297)	307,822
Long-term debt	F	893,498	9,470	902,968
Asset retirement obligations		39,516	–	39,516
Deferred income taxes	A, B, C, D & G	233,763	(7,192)	226,571
Regulatory liabilities		18,518	–	18,518
Risk management liabilities		20,598	–	20,598
Other long-term liabilities		15	–	15
Future employee obligations	C	11,480	5,762	17,242
		1,541,507	(8,257)	1,533,250
Common shares		1,023,033	–	1,023,033
Preferred shares		194,126	–	194,126
Contributed surplus		5,672	–	5,672
Accumulated other comprehensive (loss) income	C & E	(2,752)	(978)	(3,730)
Accumulated deficit	A, C, D, E & G	(9,048)	(162)	(9,210)
		$2,752,538	$ (9,397)	$2,743,141

As at December 31, 2011	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets				
Cash and cash equivalents	B	$ 4,220	$ (1,345)	$ 2,875
Accounts receivable	B	251,215	(16,681)	234,534
Inventory	B & E	11,332	1,135	12,467
Restricted cash holdings from customers		19,672	–	19,672
Regulatory assets		5,141	–	5,141
Risk management assets		68,404	–	68,404
Prepaid expense and other current assets	B, C & F	8,427	215	8,642
		368,411	(16,676)	351,735
Property, plant and equipment	A & B	2,540,215	(54,165)	2,486,050
Intangible assets	B	232,685	(55,169)	177,516
Goodwill	A, B & C	258,092	23,031	281,123
Regulatory assets	C	104,786	20,485	125,271
Risk management assets		21,642	–	21,642
Long-term investments and other assets	B, C & F	16,589	8,817	25,406
Investments accounted for by equity method	B	–	87,483	87,483
		$3,542,420	$ 13,806	$3,556,226
Liabilities And Shareholders' Equity				
Current liabilities				
Accounts payable and accrued liabilities	B	$ 327,143	$(12,721)	$ 314,422
Dividends payable		10,264	–	10,264
Short-term debt		16,824	–	16,824
Current portion of long-term debt		105,962	–	105,962
Customer deposits		25,570	–	25,570
Regulatory liabilities		503	–	503
Risk management liabilities		72,973	–	72,973
Other current liabilities	B & C	11,314	38	11,352
		570,553	(12,683)	557,870
Long-term debt	G	1,201,473	12,825	1,214,298
Asset retirement obligations		44,318	–	44,318
Deferred income taxes	A, B, C, D & G	272,272	(6,438)	265,834
Regulatory liabilities		26,686	–	26,686
Risk management		20,608	–	20,608
Other long-term liabilities		28,810	–	28,810
Future employee obligations	C	15,560	21,454	37,014
		2,180,280	15,158	2,195,438
Common shares		1,204,269	–	1,204,269
Preferred shares		194,126	–	194,126
Contributed surplus		7,441	–	7,441
Accumulated other comprehensive loss	C & E	(11,523)	(317)	(11,840)
Accumulated deficit	A, C, D, E & G	(37,599)	(1,035)	(38,634)
Non-controlling interests		5,426	–	5,426
		$3,542,420	$ 13,806	$3,556,226

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

As at December 31, 2011	Common Stock	Preferred Shares	Contributed Surplus	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Non-controlling Interests in Subsidiaries	Total Equity
Canadian GAAP	$1,204,269	$194,126	$7,441	$(11,523)	$(37,599)	$5,426	$1,362,140
A. Business combinations	–	–	–	–	3,214	–	3,214
C. Pension and other post-retirement benefits	–	–	–	(3,141)	(1,350)	–	(4,491)
D. Natural gas held in storage	–	–	–	–	950	–	950
E. De-designation of cash flow hedges	–	–	–	2,824	(2,824)	–	–
G. Income tax on preferred share dividends	–	–	–	–	(1,025)	–	(1,025)
US GAAP	$1,204,269	$194,126	$7,441	$(11,840)	$(38,634)	$5,426	$1,360,788

The statement of income for year ended December 31, 2011 reconciled from Canadian GAAP to US GAAP is as follows:

For the year ended December 31, 2011 *($ thousands except per share amounts)*	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Revenue				
Operating *(Note 25)*	B	$1,480,592	$(191,560)	$1,289,032
Unrealized (loss) on risk management contracts	D & E	(8,337)	(666)	(9,003)
Other (expenses) revenue	B	(8,799)	(637)	(9,436)
		1,463,456	(192,863)	1,270,593
Expenses				
Cost of sales *(Note 25)*	B	940,487	(107,643)	832,844
Operating and administrative	B & C	267,679	(2,790)	264,889
Accretion of asset retirement obligations		2,446	–	2,446
Depreciation, depletion and amortization	B	86,363	(6,678)	79,685
		1,296,975	(117,111)	1,179,864
Income from equity investments	B	–	75,356	75,356
Foreign exchange loss		383	–	383
Interest expense				
Short-term debt		5,836	–	5,836
Long-term debt		46,871	–	46,871
Income before income taxes		113,391	(396)	112,995
Income tax expense (recovery)				
Current	B & G	175	3,877	4,052
Future	C, D, E & G	18,614	(2,401)	16,213
Net income from operations		94,602	(1,872)	92,730
Preferred share dividends	G	11,000	(1,000)	10,000
Net income applicable to common shares		$ 83,602	$ (872)	$ 82,730
Net income per share				
Basic		$ 0.99	$ (0.01)	$ 0.98
Diluted		$ 0.98	$ (0.01)	$ 0.97
Weighted average number of shares outstanding				
Basic		84,042	–	84,042
Diluted		85,207	–	85,207

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

For the year ended December 31, 2011	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net Income applicable to controlling interests		$ 94,602	$(1,872)	$ 92,730
Other comprehensive (loss) income, net of tax				
Defined benefit plans – Unamortized actuarial gain or loss (net of tax)	C	–	(1,453)	(1,453)
Effective portion of gains (loss) on derivative instruments that qualifies as cash flow hedge (net of tax)	E	(1,420)	2,115	695
Unrealized income (loss) gain on available-for-sale financial assets (net of tax)		(7,352)	–	(7,352)
Total other comprehensive income (loss) attributable to common shareholders (net of tax)		(8,772)	662	(8,110)
Comprehensive income (loss) attributable to common shareholders and non-controlling interests (net of tax)		$ 85,830	$(1,210)	$ 84,620
Accumulated other comprehensive loss, beginning of year (net of tax)	C & E	$ (2,752)	$ (978)	$ (3,730)
Other comprehensive income (loss) (net of tax)		(8,772)	662	(8,110)
Accumulated other comprehensive loss, end of year (net of tax)		$ (11,524)	$ (316)	$ (11,840)

The Consolidated Statements of Cash Flows for the year ended December 31, 2011 reconciled from Canadian GAAP to US GAAP is as follows:

For the year ended December 31, 2011	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Net cash used in operating activities	B, C, D & E	$182,653	$ 2,749	$185,402
Net cash used in investing activities	B	(557,350)	(7,008)	(564,358)
Net cash provided by financing activities		376,808	4,000	380,808
Change in cash and cash equivalents		2,111	(259)	1,852
Cash and cash equivalents, beginning of period	B	2,109	(1,086)	1,023
Cash and cash equivalents, end of period	B	$ 4,220	$(1,345)	$ 2,875

Notes to transitional adjustments

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

A Business Combinations

Definition of business combinations

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

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

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

Acquisition-Related Transaction Costs

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

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

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

Business Combinations Achieved in Stages

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

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

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

The combined effect on the balance sheets of the adoption of ASC 805 is reflected with the following increases (decreases):

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

B Accounting for Joint Ventures

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

Under US GAAP, the Corporation accounts for its investments in jointly controlled legal entities and most limited partnerships using the equity method whereby the amount of the Corporation's investment is adjusted quarterly for the Corporation's pro-rata share of their net income or loss and reduced by the amount of any cash distribution received. The Corporation's pro-rata share of the entities' net income is recognized in the item "Income from equity investments" in the Statement of Income.

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

	January 1, 2011	December 31, 2011
Cash and cash equivalents	$ (1,086)	$ (1,345)
Accounts receivable	(16,132)	(12,005)
Inventory	–	(93)
Prepaid expenses and other current assets	(91)	(202)
Property, plant and equipment	(27,074)	(28,232)
Intangible assets	(59,919)	(55,169)
Long-term investments and other assets	691	343
Goodwill	(70)	(70)
Total assets	(103,681)	(96,773)
Accounts payable and accrued liabilities	(16,245)	(12,721)
Other current liabilities	(52)	11
Deferred income taxes	(97)	(133)
Total liabilities	(16,394)	(12,843)
Investments accounted for by equity method	$87,287	$83,930

Presentation of Equity Method Investments

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

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

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

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

C Pension and Other Post-Retirement Plans

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

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

	January 1, 2011	December 31, 2011
Accounts Receivable	$(1,503)	$ (4,676)
Goodwill	–	$ (74)
Non-current assets – Regulatory assets	$ 2,909	$20,485
Long-term investments and other assets	$ (218)	$ (381)
Deferred income taxes	$(1,144)	$ (1,637)
Other current liabilities	–	$ 27
Future employee obligations	$ 5,762	$21,454
Accumulated other comprehensive (loss) income	$(1,688)	$ (3,141)
Accumulated deficit	$(1,742)	$ (1,350)

D. Risk Management: Natural Gas Held in Storage

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

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

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

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

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

The cash flow hedges for the power delivered by ASTC to the Alberta power grid have been de-designated and the after-taxes unrealized gains have been reversed from the Statement of Accumulated Other Comprehensive Loss and recognized in earnings and accumulated deficit.

F. Debt Issuance Costs

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

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

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

G. Income Tax on Preferred Share Dividends

Measurement

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

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

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

Presentation

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

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

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

Section II – Additional Disclosures Required Under US GAAP

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

Financial Statement Effects of Rate Regulation

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

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

As at January 1, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Regulatory assets – current				
Deferred cost of gas		$ 2	–	$ 2
		$ 2	–	$ 2
Regulatory assets – non-current				
Deferred regulatory costs		$ 265	–	$ 265
Future recovery of other retirement benefits	C	1,631	2,909	4,540
Deferred depreciation and amortization		5,479	–	5,479
Deferred income taxes		28,798	–	28,798
Revenue deficiency account		40,342	–	40,342
		$ 76,515	$ 2,909	$ 79,424
Regulatory liabilities – current				
Deferred property taxes		$ 51	–	$ 51
Deferred cost of gas		825	–	825
Deferred regulatory costs		618	–	618
		$ 1,494	–	$ 1,494
Regulatory liabilities – non-current				
Future removal and site restoration costs		$ 18,518	–	$ 18,518
		$ 18,518	–	$ 18,518

As at December 31, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Regulatory assets – current				
Deferred cost of gas		$ 5,141	–	$ 5,141
		$ 5,141	–	$ 5,141
Regulatory assets – non-current				
Rate stabilization adjustment mechanism		$ 126	–	$ 126
Deferred regulatory costs		2,190	–	2,190
Pipeline rehabilitation costs		2,704	–	2,704
Future recovery of other retirement benefits	C	4,341	20,485	24,826
Deferred depreciation and amortization		9,180	–	9,180
Deferred income taxes		41,128	–	41,128
Revenue deficiency account		45,117	–	45,117
		$104,786	$20,485	$125,271
Regulatory liabilities – current				
Deferred property taxes		$ 94	–	$ 94
Deferred cost of gas		56	–	56
Deferred regulatory costs		353	–	353
		$ 503	–	$ 503
Regulatory liabilities – non-current				
LNG Partners option fees deferral		$ 3,021	–	$ 3,021
West Fraser termination payment deferral		3,454	–	3,454
Future removal and site restoration costs		20,211	–	20,211
		$ 26,686	–	$ 26,686

Goodwill

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

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

Income Taxes

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

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

As at December 31, 2011	Section I Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Income before income taxes – consolidated		$113,391	$ (396)	$112,995
Financial instruments – net	D & E	8,337	666	9,003
Income before income taxes – operating subsidiaries		121,728	270	121,998
Statutory income tax rate (%)		26.50	–	26.50
Expected taxes at statutory rates		32,258	71	32,329
Add (deduct) the tax effect of:				
Financial instruments	D & E	(2,446)	(150)	(2,596)
Rate reductions applied to deferred income tax liabilities		(1,109)	–	(1,109)
Permanent differences between accounting and tax basis of assets and liabilities	B	682	(195)	487
Non-taxable portion of capital gains (losses) on disposition of assets and investments		319	–	319
Rate adjustment		(6,861)	–	(6,861)
Taxable preferred shares	G	–	1,750	1,750
Other		660	–	660
Deferred income tax (recovery) on regulated assets		(4,725)	–	(4,725)
Prior year adjustment		11	–	11
		18,789	1,476	20,265
Income tax provision (recovery)				
Current		175	3,877	4,052
Deferred		18,614	(2,401)	16,213
		$ 18,789	$1,476	$ 20,265
Effective income tax rate (%)		16.57	1.36	17.93

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

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

As at	January 1, 2011	December 31, 2011
Property, plant and equipment and intangible assets	$216,134	$278,479
Regulatory assets	17,665	20,576
Deferred financing	(1,134)	(3,041)
Partnerships	12,994	8,448
Deferred compensation	(4,776)	(3,658)
Financial instruments	937	(2,444)
Non-capital losses	(15,249)	(33,509)
Preferred shares	275	1,025
Other	(275)	(42)
	$226,571	$265,834

Uncertain Tax Positions

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

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

Pension Plans and Retiree Benefits

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

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

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

	Defined Benefit January 1, 2011	Post-Retirement Benefits January 1, 2011	Defined Benefit December 31, 2011	Post-Retirement Benefits December 31, 2011
Amounts included in other comprehensive income (loss)				
Transitional asset (obligation)	–	–	–	–
Past service credit (cost)	–	–	(471)	–
Net actuarial gain (loss)	(2,523)	272	(3,922)	205
Total accumulated other comprehensive income (loss) on a pre-tax basis	(2,523)	272	(4,393)	205
Increase (decrease) by the amount included in deferred tax liabilities	631	(68)	1,098	(51)
Net amount in accumulated other comprehensive income (loss) after-tax adjustment	$(1,892)	$204	$(3,295)	$154

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

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

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

	Percentage of Plan Assets *(%)*
Cash and short-term equivalents	8.91
Canadian equities	31.64
Foreign equities	27.52
Fixed income instruments	31.93
	100.00

25. COMPARATIVE FIGURES

Certain comparative financial results for the year ended December 31, 2011 have been reclassified to conform to the current US GAAP financial statement presentation.

Considering the nature of some of the Corporation's financial and swap transactions, AltaGas started in 2012 to account for these transactions on a net revenue basis. To conform to current financial statement presentation, AltaGas has decreased 2011 revenues and cost of sales by $96.6 million, with no impact on net income.

Ten-Year Review of Financial Information

($ millions unless otherwise indicated)	2012	2011	2010
		(restated)	(restated)
Financial Highlights [1]			
Income Statement			
Revenue	**1,450.3**	1,270.6	1,222.1
Net revenue [2]	**664.6**	513.1	504.8
EBITDA [2]	**319.3**	257.2	234.9
Operating Income [2]			
Gas	**93.6**	105.2	95.0
Power	**76.9**	86.7	76.4
Utility	**80.7**	24.2	24.6
Corporate	**(37.1)**	(41.0)	(43.9)
	214.1	175.1	152.1
Net income	**101.8**	82.7	117.0
Net income per basic share	**1.07**	0.98	1.43
EBITDA per basic share [2]	**3.36**	3.06	2.88
Cash Flow			
Funds from operations [2]	**254.6**	213.3	191.7
Funds from operations per basic share [2]	**2.68**	2.54	2.35
Dividends/distributions per share declared	**1.40**	1.34	1.74
Balance Sheet			
Property, plant and equipment	**3,949.2**	2,486.1	1,923.5
Intangible assets	**189.8**	177.5	80.0
Total assets	**5,911.9**	3,556.2	2,743.1
Short-term debt	**66.9**	16.8	9.5
Long-term debt	**2,626.1**	1,214.3	903.0
Shareholders' equity	**1,959.8**	1,355.4	1,209.9
Share Data *(millions)*			
Shares outstanding at year-end	**105.3**	89.2	82.5
Weighted average shares outstanding for the year *(basic)*	**95.0**	84.0	81.5
Ratios *(%)*			
Return on average equity	**7.80**	7.97	9.44
Return on average invested capital	**7.69**	8.47	8.23
Debt as a percentage of total capitalization	**57.4**	49.5	42.8

1 Financial results 2010 and 2011 restated to comply with US GAAP.

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

2009	2008	2007	2006	2005	2004	2003
1,268.3	1,816.8	1,428.4	1,362.6	1,502.3	864.6	710.6
456.6	476.5	324.0	318.9	296.9	250.4	217.3
247.8	245.4	245.4	172.6	156.8	134.5	122.8
102.9	103.6	59.3	63.4	60.1	47.9	43.3
88.0	117.9	94.6	90.9	48.7	35.8	31.6
7.5	–	–	–	6.2	7.9	8.7
(27.7)	(43.1)	(27.3)	(27.6)	(6.9)	–	–
170.6	178.4	125.5	126.7	108.1	91.6	83.6
141.3	163.6	108.8	114.5	90.3	65.8	38.3
1.80	2.38	1.90	2.06	1.67	1.33	0.84
3.16	3.57	4.28	3.10	2.90	2.72	2.70
202.3	217.1	162.9	161.7	129.0	108.6	90.2
2.58	3.15	2.84	2.92	2.39	2.20	1.98
2.16	2.13	2.065	1.995	1.85	1.31	0.38
1,857.1	1,436.7	682.3	677.9	645.4	746.7	677.9
128.9	138.9	95.7	103.3	110.9	113.1	101.0
2,628.9	2,132.3	1,172.7	1,109.6	1,068.3	1,108.6	919.3
14.5	4.5	3.6	–	2.7	7.0	4.5
1,000.1	560.8	217.2	265.5	266.3	352.5	392.4
1,048.9	957.4	584.7	529.4	478.6	483.5	363.3
80.3	71.9	58.1	56.4	54.6	53.2	45.7
78.5	68.8	57.4	55.5	54.0	49.4	45.5
13.6	19.6	19.8	22.7	18.4	15.7	10.9
10.0	13.6	16.2	16.3	13.0	11.6	11.1
49.2	37.8	27.4	33.4	36.0	42.6	52.2

Ten-Year Review of Operating Information

	2012	2011	2010
Operating Statistics			
Gas			
Extraction inlet gas processed *(Mmcf/d)* [1]	**889**	883	–
Extraction ethane volumes *(Bbls/d)* [2]	**25,499**	26,565	25,453
Extraction NGL volumes *(Bbls/d)* [2]	**14,593**	14,513	12,654
Total extraction volumes *(Bbls/d)* [2]	**40,092**	41,078	38,107
Frac spread – realized *($/Bbl)* [2,3]	**30.83**	33.67	27.27
Frac spread – average spot price *($/Bbl)* [2,4]	**29.22**	42.88	31.95
Field processing throughput *(gross Mmcf/d)* [2]	**372**	391	423
Field processing capacity Utilization *(%)* [1]	**27**	33	35
Average gas volumes marketed *(GJ/d)* [2,7]	**356,526**	369,603	386,004
Power			
Volume of power sold *(GWh)* [2]	**3,317**	3,003	2,828
Price received on the sale of power *($/MWh)* [2]	**69.42**	75.94	66.79
Alberta Power Pool price *($/MWh)* [2]	**64.32**	76.22	50.76
Canadian utilities			
Natural gas deliveries – end-use *(PJ)* [5]	**28.5**	21.8	19.90
Natural gas deliveries – transportation *(PJ)* [5]	**6.8**	4.6	5.30
U.S. utilities [6]			
Natural gas deliveries – end-use *(Bcf)* [5]	**26.0**	–	–
Natural gas deliveries – transportation *(Bcf)* [5]	**13.9**	–	–
Service sites [8]	**547,977**	115,011	74,664
Degree day variance from normal *(%)*			
AUI [9]	**(0.7)**	–	(1.60)
Heritage Gas [9]	**(9.1)**	(12.7)	(13.20)
SEMCO Gas [10]	**(0.3)**	–	–
ENSTAR [10]	**9.6**	–	–

1 *As at December 31.*

2 *Average for the period.*

3 *Realized frac spread or NGL margin, expressed in dollars per barrel of NGL, is derived from sales recorded by the segment during the period for frac exposed volumes plus the settlement value of frac hedges settled in the period less shrinkage gas and extraction premiums, divided by the total frac exposed volumes produced during the period.*

4 *Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, are indicative of the average sales price that AltaGas receives for propane, butane and condensate less shrinkage gas and extraction premiums, divided by the respective frac exposed volumes for the period.*

5 *Petajoule (PJ) is one million gigajoules. Bcf is one billion cubic feet.*

6 *Results for U.S. utilities are from August 30, 2012.*

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

2009	2008	2007	2006	2005	2004	2003
–	–	–	–	–	–	–
26,817	24,795	13,355	13,132	13,155	8,602	4,056
13,236	12,242	6,752	6,564	6,202	4,834	3,519
40,053	37,037	20,108	19,696	19,357	13,436	7,575
23.46	26.97	21.38	18.47	9.31	10.51	6.23
19.51	28.79	22.48	18.47	9.31	10.51	6.23
453	541	527	555	563	560	520
39	46	52	54	60	61	61
354,513	302,392	388,217	327,057	312,272	174,337	–
2,726	2,623	2,661	2,878	3,466	3,481	3,266
68.97	84.51	68.59	69.26	54.59	48.77	47.56
47.84	89.95	66.84	80.48	70.19	54.54	62.98
6.62	–	–	–	10.5	14.7	14.7
0.55	–	–	–	9.5	11.6	10.5
–	–	–	–	–	–	–
–	–	–	–	–	–	–
72,717	–	–	–	61,447	60,430	59,543
9.90	–	–	–	(1.4)	2.6	6.9
(1.00)	–	–	–	(5.7)	2.3	
–	–	–	–	–	–	–
–	–	–	–	–	–	–

8 *Service sites reflect all of the service sites of AUI, PNG, Heritage Gas and U.S. utilities, including transportation and non regulated business lines.*

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

10 *A degree day for U.S. utilities is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior fifteen years for SEMCO Gas and during the prior ten years for ENSTAR.*

Shareholder Information

2012 Dividend History

Ex-Dividend Date	Record Date	Payment Date	Amount
January 23, 2012	January 25, 2012	February 15, 2012	$0.115
February 23, 2012	February 27, 2012	March 15, 2012	$0.115
March 22, 2012	March 26, 2012	April 16, 2012	$0.115
April 23, 2012	April 25, 2012	May 15, 2012	$0.115
May 23, 2012	May 25, 2012	June 15, 2012	$0.115
June 21, 2012	June 25, 2012	July 16, 2012	$0.115
July 23, 2012	July 25, 2012	August 15, 2012	$0.115
August 23, 2012	August 27, 2012	September 17, 2012	$0.115
September 21, 2012	September 25, 2012	October 15, 2012	$0.120
October 23, 2012	October 25, 2012	November 15, 2012	$0.120
November 22, 2012	November 26, 2012	December 17, 2012	$0.120
December 21, 2012	December 27, 2012	January 15, 2013	$0.120
Total 2012 Dividends Declared			$1.400

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

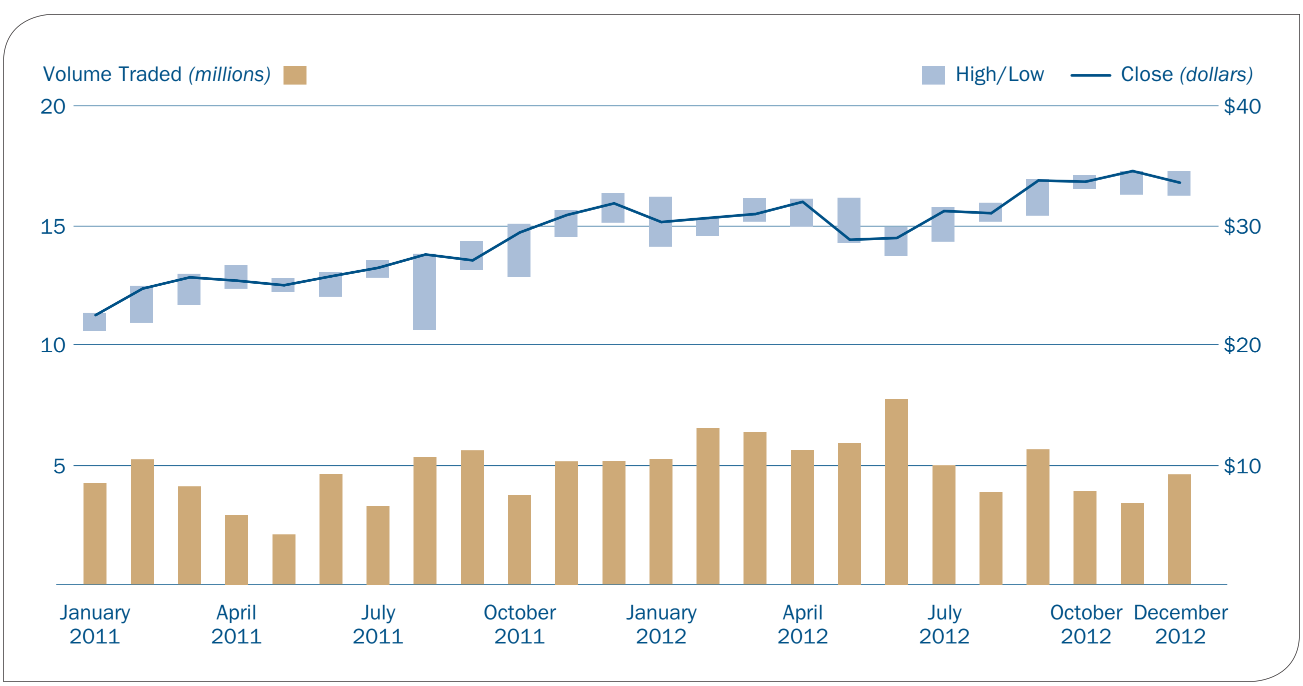
AltaGas has adopted a Dividend Reinvestment and Optional Share Purchase Plan ("Plan") for holders of common shares of AltaGas Ltd.

The Plan provides shareholders with a convenient and economical way to maximize their investment in AltaGas. The Plan enables eligible shareholders to direct cash dividends paid by AltaGas in respect of their existing shares be reinvested at 95 per cent of the average market price (as defined in the Plan) of a share. Eligible shareholders can also make optional share purchases at the weighted average market price subject to Plan limits.

If you wish to participate in the Plan, eligible registered shareholders must enroll directly with Computershare Trust Company of Canada, while beneficial shareholders should simply contact their broker, investment dealer, financial institution or other nominee through which shares are held, as they must enroll on your behalf.

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

AltaGas Share Price and Volume (ALA)



Corporate Information

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

Management Team

David W. Cornhill
Chairman and Chief Executive Officer

Dennis A. Dawson
Vice President General Counsel
and Corporate Secretary

David M. Harris
President Gas and Power

John E. Lowe
Executive Vice President
Corporate Development

Deborah S. Stein
Senior Vice President Finance
and Chief Financial Officer

Kent E. Stout
Vice President
Corporate Resources

Randy W. Toone
President Utilities

David R. Wright
Executive Vice President

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

Stock Exchange Listing
Toronto Stock Exchange:
ALA, ALA.PR.A, ALA.PR.U

Annual Meeting
The annual meeting will be held at 2:30 p.m. MDT on Thursday, April 25, 2013 at
Calgary Petroleum Club
319 - 5th Avenue S.W.
Calgary, Alberta

Definitions

Bbls/d	barrels per day
Bcf	billion cubic feet
EBITDA	earnings before interest, taxes, depreciation and ammortization
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
PJ	petajoule
MMBTU	million British thermal unit

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Forward-looking Information

This report may contain certain information that is forward looking and is subject to important risks and uncertainties. The words "may", "would", "could", "should", "will", "intend", "plan", "anticipate", "expect", "believe", "seek", "propose", "estimate", "project", "outlook", "forecast" or other similar words are used to identify such forward-looking information. Forward-looking statements in this report are intended to provide AltaGas security holders and potential investors with information regarding AltaGas and its subsidiaries, including management's assessment of AltaGas' and its subsidiaries' future financial and operations plans and outlook. Forward-looking statements in this report may include, among others, statements regarding business objectives and anticipated business prospects, projects and financial performance of AltaGas and its subsidiaries, expectations or projections about the future, and strategies and goals for growth and expansion. All forward-looking statements reflect AltaGas' beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of AltaGas to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of AltaGas' assets, the price of energy commodities, regulatory processes and decisions, changes in environmental and other laws and regulations, competitive factors in the natural gas and power energy sectors, construction and completion of capital projects, labour, equipment and material costs, access to capital markets, interest and currency exchange rates, weather, economic conditions in North America. This list should not be considered to be exhaustive. By its nature, forward-looking information is subject to various risks and uncertainties, which could cause AltaGas' actual results and experience to differ materially from the anticipated results or expectations expressed. Additional information on these and other factors is available in the reports filed by AltaGas with Canadian securities regulators and available through the SEDAR system at www.sedar.com. Readers are cautioned to not place undue reliance on this forward-looking information, which is given as of the date it is expressed in this report or otherwise, and to not use future-oriented information or financial outlooks for anything other than their intended purpose. AltaGas undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by law.

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TSX: **ALA**

Investor Relations

AltaGas trades on the Toronto Stock Exchange
TSX: **ALA, ALA.PR.A, ALA.PR.U**

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