ALTAGAS LTD.

Annual Information Form

For the year ended December 31, 2010

Dated: March 4, 2011

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All dollar amounts in this Annual Information Form are in Canadian dollars unless otherwise stated.

FORWARD-LOOKING INFORMATION

This Annual Information Form contains forward-looking statements. When used in this Annual Information Form the words "may", "would", "could", "will", "intend", "plan", "anticipate", "believe", "seek", "propose", "estimate", "expect", and similar expressions, as they relate to the Corporation, are intended to identify forward-looking statements. In particular, this Annual Information Form contains forward-looking statements with respect to, among other things, business objectives, expected growth, results of operations, performance, business projects and opportunities and financial results.

Specifically, such forward-looking statements are set forth in respect of AltaGas' overall strategy under the heading "AltaGas' Strategy", including with respect to the relative contribution of the gas, power and utility businesses to revenue growth, statements as they relate to gas opportunities with respect to: expectations for the WCSB; growth opportunities from plant modifications, increasing interests, acquiring and constructing infrastructure and growing demand; the anticipated impact of the Harmattan Co-Stream Project and the Gordondale project; the contribution of AltaGas' extraction infrastructure to throughput, utilization and profitability; the availability of opportunities to build or acquire gathering, processing, extraction or transmission infrastructure and generate operating synergies; and the impact of growing natural gas production in northeast British Columbia and northwest Alberta; statements as they relate to power opportunities with respect to: power demand growth and price recovery; the timing of new power generation and the impact of the planned decommissioning of thermal plants in Alberta, opportunities to develop new clean power generation capacity, the anticipated impact of the Forrest Kerr Project; and statements as they relate to utility opportunities to build or expand natural gas distribution infrastructure in Alberta, Nova Scotia or the Northwest Territories. In addition, such forward-looking statements are set forth under:

- "Gas Division – Transmission", including in respect of expectations for volume commitments for 2011 and thereafter in relation to Suffield and the extension of the life of the Kahntah pipeline asset;

- "Gas Division – Field Gathering and Processing", including in respect of expectations with respect to levels of producer activity and demand for gathering and processing facilities and services and AltaGas' competitiveness in the midstream marketplace;

- "Power Division", including in respect of expectations for growth through renewable energy projects, the timing of construction and completion of the Forrest Kerr Project, the timing of development and the environmental attributes of the Glenridge Wind Development project, the timing of development and construction for the McLymont Creek, Volcano, Log Creek and Kookipi Creek run-of-river projects, the ability to generate further growth for the power infrastructure business with its renewable energy portfolio, the long-term price environment for power, the drivers of growth in the power business and the timing of development and intentions with respect to the development of AltaGas' hydroelectric and other wind power development projects in Canada and the United States;

- "Utility Division", including in respect of expectations for growth in new service sites and activations, capital expenditures for 2011 and access to adequate supplies of natural gas.

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, and general economic conditions and the other factors discussed under the heading "Risk Factors" in this Annual Information Form.

Many factors could cause AltaGas' or any particular segment's actual results, performance or achievements to vary from those described in this Annual Information Form, including without limitation those listed above and the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this Annual Information Form as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this Annual Information Form, should not be unduly relied upon. Such statements speak only as of the date of this Annual Information Form. 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 Annual Information Form are expressly qualified by this cautionary statement.

Financial outlook information contained in this Annual Information Form 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 Annual Information Form should not be used for purposes other than for which it is disclosed herein.

GLOSSARY

In this Annual Information Form, unless the context otherwise requires, the following terms have the indicated meanings. A reference to an agreement means the agreement as amended, supplemented or restated from time to time.

"**AESO**" means Alberta Electric System Operator;

"**AltaGas**" or the "**Corporation**" means AltaGas Ltd., including, where the context requires, the operating affiliates of AltaGas;

"**AltaGas LP #1**" means AltaGas Holding Limited Partnership No. 1, a limited partnership established under the laws of Alberta and dissolved pursuant to the Corporate Arrangement;

"**AltaGas LP #1 B units**" means Class B limited partnership units of AltaGas LP #1;

"**AltaGas LP #2**" means AltaGas Holding Limited Partnership No. 2, a limited partnership established under the laws of Alberta and dissolved pursuant to the Corporate Arrangement;

"**AltaGas LP #2 B units**" means Class B limited partnership units of AltaGas LP #2;

"**AltaGas Services**" or "**ASI**" means AltaGas Services Inc., a predecessor by amalgamation to AltaGas Ltd.;

"**ASTC Partnership**" or "**ASTC**" means ASTC Power Partnership;

"**AUI**" means AltaGas Utilities Inc.;

"**AUC**" means the Alberta Utilities Commission;

"**Balancing Pool**" means the Alberta governmental agency established to manage unsold PPAs from the original PPA auction, and which serves as a liability backstop for all PPAs;

"**Bankruptcy Act**" means the *Bankruptcy and Insolvency Act* (Canada), R.S.C. 1985, c. B-3, as amended from time to time, including the regulations from time to time promulgated thereunder;

"**Bbls**" means stock tank barrels of ethane and NGLs, expressed in standard 42 U.S. gallon barrels or 34.972 imperial gallon barrels;

"**Bbls/d**" means Bbls per day;

"**Bcf**" means 1,000,000 Mcf of natural gas;

"**Bcf/d**" means Bcf per day;

"**BMWLP**" means Bear Mountain Wind Limited Partnership;

"**Board of Directors**" means the board of directors of AltaGas, as from time to time constituted;

"**BPA**" means the Balancing Pool Administrator;

"**CBCA**" means the *Canada Business Corporations Act*, R.S.C. 1985, c. C 44, as amended from time to time, including the regulations from time to time promulgated thereunder;

"**CBM**" means coal bed methane;

"**CIAC**" means contributions in aid of construction;

"**Corporate Arrangement**" means the arrangement, under the provisions of section 192 of the CBCA, involving, among others, AltaGas, the Trust, Holding Trust, the General Partner, AltaGas LP #1 and AltaGas LP #2, pursuant to which the business of the Trust was reorganized into a corporation effective July 1, 2010;

"**DBRS**" means DBRS Limited;

"**Degree Day**" means the amount that the daily mean temperature deviates below 15 degrees Celsius at AUI and below 18 degrees Celsius at Heritage Gas, such that a one degree difference equates to one Degree Day;

"**EDS**" means Ethylene Delivery System;

"**EEEP**" means the Edmonton ethane extraction plant and related facilities;

"**ERCB**" means the Alberta Energy Resources Conservation Board;

"**Exchangeable units**" means AltaGas LP #1 B units and AltaGas LP #2 B units, if any;

"**Exempt Plans**" means, collectively, trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, registered disability savings plans and tax-free savings accounts, each as defined in the Tax Act;

"**General Partner**" means AltaGas General Partner Inc., a direct wholly-owned subsidiary of AltaGas and, prior to the Corporate Arrangement, the general partner of AltaGas LP #1 and AltaGas LP #2;

"**GJ**" means gigajoule or 1,000,000,000 joules;

"**GJ/d**" means GJ per day;

"**GreenWing**" means GreenWing Energy Development Limited Partnership;

"**GWh**" means gigawatt-hour or 1,000,000,000 watt-hours; the watt-hour is equal to one watt of power flowing steadily for one hour;

"**Harmattan Complex**" means the Harmattan natural gas liquids extraction plant and associated facilities;

"**Heritage Gas**" means Heritage Gas Limited;

"**Holding Trust**" means AltaGas Holding Trust, an unincorporated investment trust, all of the beneficial interests of which were owned by the Trust prior to the Corporate Arrangement, pursuant to which it was dissolved;

"**Ikhil Joint Venture**" means the joint venture between AltaGas, Inuvialuit Petroleum Corporation and ATCO Midstream NTW Ltd., which owns and operates two gas wells, a processing facility and a pipeline that delivers natural gas to Inuvik Gas and NWTPC;

"**Inuvik Gas**" means Inuvik Gas Ltd.;

"**JEEP**" means the Joffre ethane extraction plant and related facilities;

"**JFP**" means Joffre Feedstock Pipeline;

"**km**" means kilometre;

"**m^3**" means a cubic metre of natural gas at standard conditions of measurement;

"**MBbls**" means 1,000 Bbls;

"**Mcf**" means a thousand cubic feet of natural gas at standard imperial conditions of measurement;

"**Mcf/d**" means Mcf per day;

"**Mm**" means millions;

"**Mmcf**" means a million cubic feet of natural gas at standard conditions of measurement;

"**Mmcf/d**" means Mmcf per day;

"**MW**" means megawatt; one MW is 1,000,000 watts; the watt is the basic electrical unit of power;

"**MWh**" means megawatt-hour or 1,000,000 watt-hours; the watt-hour is equal to one watt of power flowing steadily for one hour;

"**NGL**" or "**NGLs**" means natural gas liquids, which includes primarily propane, butane and condensate;

"**NovaGreen**" means NovaGreen Power Inc.;

"**NGTL**" means NOVA Gas Transmission Ltd.;

"**NSUARB**" means the Nova Scotia Utility and Review Board;

"**NW Projects**" means the three run-of-river hydroelectric projects in Northwest B.C.: Forrest Kerr, McLymont Creek and Volcano Creek;

"**NWTPC**" means the Northwest Territories Power Corporation;

"**NWTPUB**" means the Northwest Territories Public Utility Board;

"**Plan**" means the Dividend Reinvestment and Optional Share Purchase Plan of the Corporation;

"**Pool**" means the Alberta Power Pool;

"**PJ**" means Petajoule which is one million GJ;

"**PPA**" means power purchase arrangement;

"**Preferred Shares**" means the preferred shares of AltaGas as a class, including, without limitation, the Series A Shares and Series B Shares;

"**Provident**" means Provident Energy Ltd.;

"**RAPP**" means the rolling 30-day average Pool price of electricity in Alberta;

"**RECS**" means Renewable Energy Credits;

"**RRO**" means the Rate Regulated Option;

"**Rep Agreements**" mean the Representation, Management and Processing Agreements at the Harmattan Complex;

"**S&P**" means Standard & Poor's Ratings Services;

"**Series A Shares**" means the cumulative redeemable 5-year rate reset preferred shares, Series A of AltaGas;

"**Series B Shares**" means the cumulative redeemable floating rate preferred shares, Series B of AltaGas;

"**shares**" means common shares of AltaGas;

"**share options**" means options to acquire shares granted pursuant to AltaGas' share option plan;

"**shareholders**" means the holders of shares;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c.1 (5th Supp.), as amended from time to time, including the regulations from time to time promulgated thereunder;

"**Taylor**" means AltaGas Holding Partnership, formerly Taylor NGL Limited Partnership, a limited partnership created pursuant to the laws of Ontario and reconstituted under the laws of Alberta;

"**Tcf**" means 1,000,000,000 Mcf;

"**TransAlta**" means TransAlta Utilities Corporation;

"**TransCanada**" means TransCanada Energy Ltd.;

"**Trust**" means AltaGas Income Trust, a trust established under the laws of Alberta and dissolved pursuant to the Corporate Arrangement;

"**Trust units**" means trust units of the Trust;

"**TSX**" means the Toronto Stock Exchange;

"**Unit**" or "**units**" means Trust units and Exchangeable units;

"**Utility Group**" means AltaGas Utility Group Inc.;

"**WCSB**" means Western Canada Sedimentary Basin; and

"**Younger Extraction Plant**" means the Younger extraction plant and related facilities.

METRIC CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply by
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls	6.290
tonnes	long tons	0.984
feet	metres	0.305

To Convert From	To	Multiply By
metres	feet	3.281
miles	km	1.609
km	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoule	Mcf	0.9482

CORPORATE STRUCTURE

INCORPORATION

AltaGas' head, principal and registered office is located at 1700, 355 – 4th Avenue S.W., Calgary, Alberta, T2P 0J1. AltaGas is a public company trading on the Toronto Stock Exchange under the symbol "ALA".

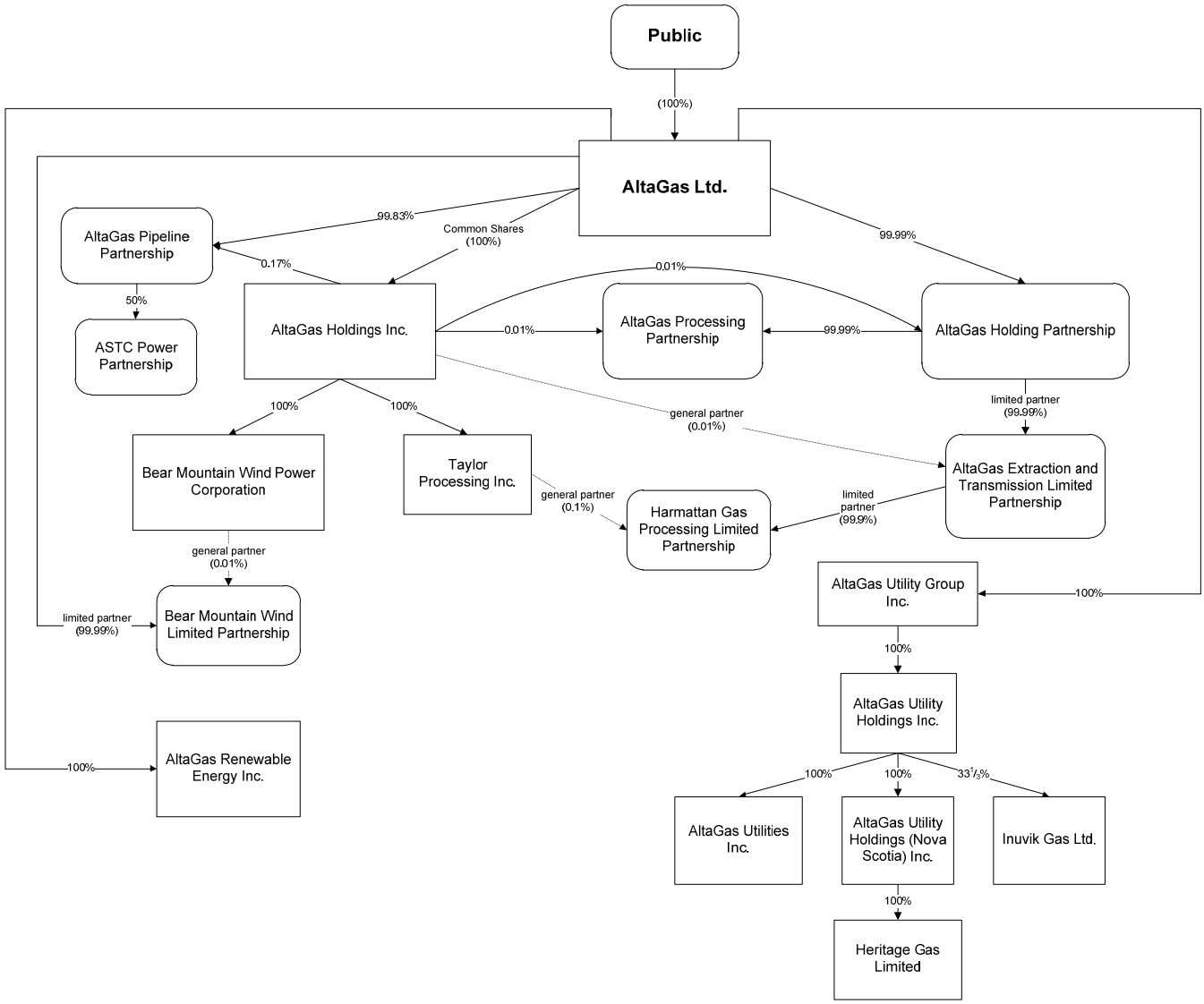
Effective July 1, 2010 the Trust was reorganized pursuant to the Corporate Arrangement as a result of the federal government's announcement on October 31, 2006 that the tax treatment of income trusts would change on January 1, 2011. Pursuant to the Corporate Arrangement, holders of Trust units received one common share of AltaGas per Trust unit held and holders of AltaGas LP #1 B units received one common share of AltaGas per AltaGas LP #1 B unit held.

At December 31, 2010 AltaGas had 82,526,399 outstanding common shares and 8,000,000 outstanding Series A Shares.

AltaGas' fiscal year-end is December 31 and references in this Annual Information Form to particular years mean AltaGas' fiscal years unless otherwise indicated.

SUBSIDIARIES

The following organization chart presents the name and the jurisdiction of incorporation of AltaGas' material subsidiaries as at December 31, 2010. The chart does not include all of the subsidiaries of AltaGas. The assets and revenue of excluded subsidiaries in the aggregate did not exceed 20% of the total consolidated assets or total consolidated revenues of AltaGas as at and for the year ended December 31, 2010.



Note:

(1) Each corporation listed above (other than Taylor Processing Inc., AltaGas Renewable Energy Inc. and AltaGas Utility Holdings (Nova Scotia) Inc.) is a corporation incorporated or formed by amalgamation or continuance under the CBCA. Each of Taylor Processing Inc. and AltaGas Utility Holdings (Nova Scotia) Inc. is a corporation incorporated under the *Business Corporations Act* (Alberta) and AltaGas Renewable Energy Inc. is a corporation incorporated under the *Business Corporations Act* (British Columbia). Each partnership listed above (other than AltaGas Holding Partnership and Bear Mountain Wind Limited Partnership) was established under the laws of Alberta. AltaGas Holding Partnership was established under the laws of Ontario and Bear Mountain Wind Limited Partnership was established under the laws of British Columbia.

OVERVIEW OF THE BUSINESS

AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. With physical and economic links along the energy value chain together with its efficient and reliable assets, market knowledge and financial discipline, AltaGas has provided strong, stable and predictable returns for 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.

At the end of 2010, AltaGas completed an internal reorganization that formally established three operating divisions, Gas, Power and Utility. AltaGas' Gas business touches more than 2 Bcf/d of gas and includes natural gas gathering and processing, extraction, transmission and storage. The Power business includes conventional power generation in Alberta and renewable power generation in British Columbia. The Utility business is a business in which earnings are driven primarily by regulated rates of return and cost-of-service recovery.

At December 31, 2010, AltaGas reported consolidated financial and operating results on the basis of four reporting segments:

- Gas
    - Extraction and Transmission consists of AltaGas' interests in ethane and NGL extraction plants and natural gas and NGL transmission systems;
    - Field Gathering and Processing includes the natural gas gathering and processing business; and
    - Energy Services consists of two main businesses: energy management services and gas services.
- Power
    - AltaGas' interests in coal-fired and gas-fired generation, wind power, run-of-river power and interests in wind and run-of-river renewable power projects under development.
- Utility
    - Natural gas transmission and distribution facilities in Alberta, Nova Scotia and the Northwest Territories, Canada
- Corporate
    - Corporate includes the cost of providing services and general corporate overhead, investments in public and private entities and the effects of the changes in the value of risk management assets and liabilities.

ALTAGAS' VISION AND OBJECTIVE

AltaGas' vision is to be a leading North American energy infrastructure company with a focus in Canada and the northern and western United States. The 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 returns. Over the past seventeen years AltaGas has built a portfolio of assets that provide the platform to support its future growth. The Corporation will continue to seek to invest in projects that provide returns that are accretive to cash flow and earnings and which in turn provide stable and growing dividends and capital appreciation.

ALTAGAS' STRATEGY

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

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

AltaGas' Board of Directors reviews the strategy annually, consistent with its mandate of overseeing and directing the Corporation's strategic direction. AltaGas 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 must meet strategic, operating and financial criteria.

Gas – Business Strategy

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

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

The Gas business includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1,594 Mmcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin-based revenues;
- Five natural gas transmission systems with combined transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity of 151,600 Bbls/d;
- More than 70 gathering and processing facilities in 31 operating areas in western Canada and a network of approximately 6,500 km of gathering and sales lines that gather gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets;
- A 50 percent ownership interest in Sarnia Storage Pool Limited Partnership, which owns the 5.3 Bcf natural gas storage facility in Sarnia, Ontario connected to the Dawn hub in eastern Canada;
- Harmattan co-streaming project (the "Harmattan Co-Stream Project") under construction with an expected in-service date of first quarter 2012;
- Gordondale gas processing plant with deep-cut extraction capability in the regulatory approval process with planned in-service date of late 2012;
- A 50 percent interest in a natural gas storage project under development in Nova Scotia with potential gross storage capacity of 10 Bcf and an interest in a project in Michigan with potential storage capacity of approximately 50 Bcf; and
- Energy consulting, natural gas buying and selling and gas transportation services to optimize the value of the infrastructure assets and meet customer needs.

AltaGas pursues opportunities to enhance long-term shareholder value and deliver value to its customers. AltaGas' objectives for the Gas business are to:

- Increase throughput and utilization of existing facilities;
- Be the most cost effective provider of mid-stream services while delivering reliability and operating in a safe manner;
- Mitigate volume risk by directly recovering operating costs from customers;
- Acquire and develop new gas infrastructure assets to meet customers' needs; and
- Enhance operational efficiencies and returns through consolidation of facilities, plant upgrades and integration of business lines across the energy value chain.

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

Until recently, the WCSB was considered to be a maturing basin. Recent technological advancements have resulted in a significant change in the cost of production of natural gas in the 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 gas and solution gas thereby increasing the expected demand for processing capacity that allows producers to earn higher netbacks on liquids-rich gas.

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

The natural gas supply to all extraction plants depends on natural gas demand pull from residential, commercial and industrial usages inside and outside of western Canada and gas liquids demand pull from the Alberta petrochemical, propane heating and Canadian oil and gas industries. AltaGas' extraction plants near Empress, Alberta rely on natural gas exports via the NGTL eastern gate, while the Younger Extraction Plant is supplied from the robust natural gas producing region of northeast British Columbia. The Harmattan Complex is a significant service provider with a large capture area in west central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and increase asset utilization and profitability. The Harmattan Co-Stream Project is expected to increase utilization at the plant. The cost-of-service arrangement for the Harmattan Co-stream Project is also expected to add long-life, low-risk stable cash flow that is expected to further strengthen AltaGas' business risk profile and create 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 from non-core activities such as processing. The Corporation also expects opportunities to increase volumes by tying-in new wells and building or purchasing adjoining facilities and systems to create larger processing infrastructure to capture operating synergies and enhance competitive advantages. The strategic location of some of its existing infrastructure will allow AltaGas to capitalize on growing natural gas production in northeast British Columbia and northwest Alberta, as well as unconventional sources of gas such as shale and CBM. AltaGas is able to relocate units quickly and cost-effectively to respond to the changing processing needs of its customers since most of its field gas compression and processing units are skid-mounted. The proposed Gordondale plant will meet liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. Overall, the diverse nature of its field processing and extraction infrastructure should provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability. The contractual underpinning of the Gordondale plant is expected to provide AltaGas with stable cash flows and the opportunity to further enhance returns due to the strategic location of the facility.

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

Power - Business Strategy

The Power business includes conventional power generation in Alberta and wind power generation in British Columbia. This business also includes several wind and run-of-river projects under development in Canada and the United States as well as the 195 MW Forrest Kerr run-of-river project under construction in northwest British Columbia.

The power business comprises 509 MW of total power generation capacity in Alberta and British Columbia.

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

AltaGas has 39 MW of gas-fired power peaking capacity in southern Alberta. In late 2010 the Corporation commissioned the 15 MW gas-fired cogeneration facility at the Harmattan Complex. This 54 MW of gas-fired capacity provides fuel diversity to AltaGas' Power business and partially backstops outages at Sundance. The cogeneration facility provides steam to the gas processing facility as well as base-load power to the Alberta electric

grid. The peaking plants also provide revenue from the sale of energy and ancillary services due to their quick ramp-up capability.

AltaGas employs a power hedging strategy which is designed to balance market and operational risk, thereby seeking to reduce the exposure to power prices in Alberta and provide earnings stability in the power business in Alberta. Hedges are executed with industry participants and are subject to credit reviews and credit thresholds in the normal course of business.

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

AltaGas' operating renewable power generation includes the 102-MW Bear Mountain Wind Park near Dawson Creek, British Columbia and an effective 25 percent interest in a 7-MW run-of-river hydroelectric generation facility near Boston Bar, British Columbia.

Power from the Bear Mountain Wind Park is sold to BC Hydro under a 25-year electricity purchase agreement. AltaGas retained the green attributes and RECs related to the project. These credits have recently been designated as certified by the California Energy Commission. In addition, the Bear Mountain Wind Park has qualified for the Federal Government of Canada's ecoEnergy renewable initiative (“eRPI”), which grants $10/MWh generated by the Bear Mountain Wind Park for 10 years beginning on October 31, 2009. AltaGas has entered into a long-term service agreement with Enercon GmbH, manufacturer of the turbines, to operate and maintain the wind turbines.

AltaGas pursues opportunities to enhance long-term shareholder value. AltaGas' objectives for the Power business are to:

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

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

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

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

AltaGas' primary means of securing long-term power sales is through its Commercial and Industrial ("C&I") power retail business. AltaGas actively markets electricity directly to end-users, enabling the 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.

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

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

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

Utility - Business Strategy

AltaGas owns and operates utility assets that deliver natural gas to end-users in Alberta, Nova Scotia and Inuvik, Northwest Territories. The Utility business is comprised of 100 percent interests in AUI in Alberta and Heritage Gas in Nova Scotia and a one-third interest in each of Inuvik Gas and the Ikhil Joint Venture in the Northwest Territories. This low-risk, long-life energy infrastructure is underpinned by regulated returns and cost-of-service recovery that provide stable and predictable cash flows. The Utility business enhances the diversification of AltaGas portfolio of energy infrastructure assets and strengthens the Corporation's business risk profile, thus allowing AltaGas to meet its objective of generating superior economic returns by investing in low-risk, long-life assets with stable earnings.

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

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

AltaGas Utilities Inc.

AUI serves primarily residential and small commercial consumers located in smaller population centres or rural areas of Alberta. The growth of AUI's service sites and business generally occurs through infill growth in established franchises. Growth for space and water heating in AUI's service areas continues to be concentrated in town distribution systems and relates to servicing new homes and commercial developments with natural gas. AUI serves almost all of the potential market in its existing service areas.

Heritage Gas Ltd.

Heritage Gas has the exclusive rights to distribute natural gas to all or part of six counties in Nova Scotia, including the Halifax Regional Municipality. Heritage Gas in Nova Scotia is a relatively new energy alternative in the province and will continue to require significant capital investment as the natural gas distribution infrastructure is constructed to provide new services to consumers in its franchise areas. Heritage Gas provides Nova Scotia consumers with the opportunity to switch heating fuel sources, mainly from oil or electricity to natural gas.

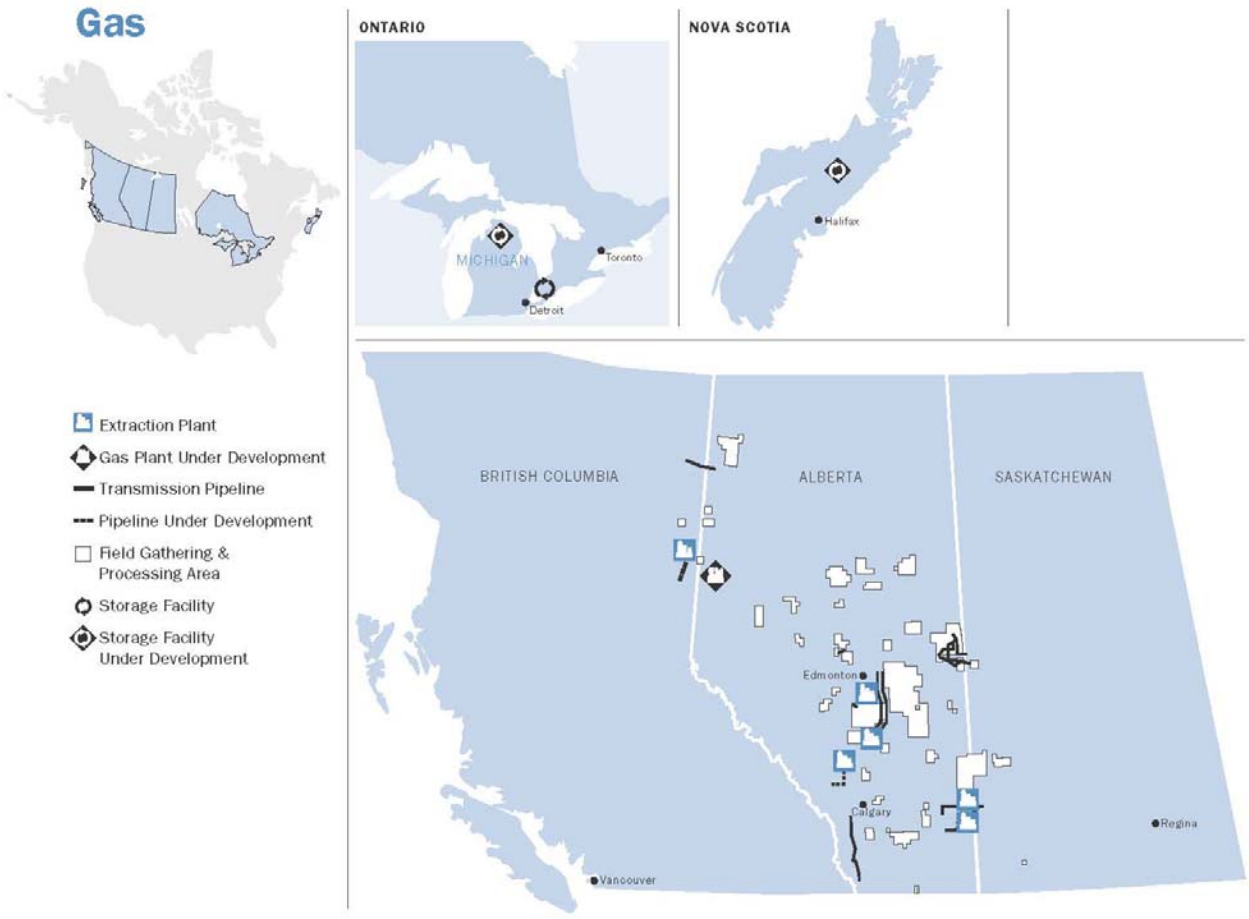
Inuvik Gas Ltd. and Ikhil Joint Venture

Inuvik Gas serves residential and commercial consumers in Inuvik, Northwest Territories. The Ikhil Joint Venture produces natural gas for sale under long-term contracts based on the price of diesel fuel. These contracts are with the NWTPC and Inuvik Gas.

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

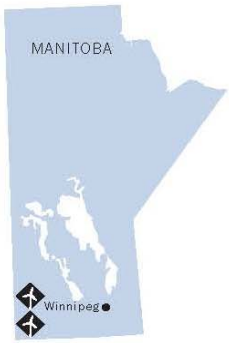
- Grow its existing infrastructure through infill and expansion of services within current franchise areas;
- Continue the 20-year system rejuvenation program in Alberta to maintain public and worker safety, and to ensure reliable and efficient long-term operation of the gas delivery systems;
- Continue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

ALTAGAS' GEOGRAPHIC FOOTPRINT



Power

- Coal-Fired Power Generation
- Gas-Fired Power Generation
- Gas-Fired Power Generation Under Development
- Wind Power Generation
- Wind Power Generation Under Development
- Hydro Power Generation
- Hydro Power Generation Under Development
- Hydro Power Generation Under Construction
- Waste Heat Recovery Under Development



Utility

- Field Gathering & Processing Area
- Gas Distribution Area
- Transmission Pipeline

GENERAL DEVELOPMENT OF ALTAGAS' BUSINESS

HISTORICAL DEVELOPMENT

ASI commenced operations on April 1, 1994 with a founding vision to build a major Canadian natural gas midstream business combining a portfolio of natural gas-related services with long-life assets to grow net income. The concept of a distinct, full-service midstream business was unique in Canada at the time. ASI commenced operations with two major contracts to provide transportation, regulatory and gas management services. The revenue generated from these contracts during 1994 and 1995, together with private placement equity financings, provided the funds for ASI to establish its midstream asset base and make the transition from a consulting services company to a midstream operating company.

Development of the Gas Business

The nature of AltaGas' participation in the midstream industry evolved from holding primarily service contracts and non-operated investments to include fully-operated natural gas facilities of which AltaGas owns 100 percent or in which it has a controlling interest.

In 2007 AltaGas offered to acquire all of the outstanding limited partnership units of Taylor NGL Limited Partnership. On January 10, 2008 AltaGas completed the acquisition of Taylor for the aggregate purchase price of $593.6 million, including $256.3 million of cash and 7.7 million Trust units valued at $198.9 million for all the outstanding limited partnership units of Taylor not previously owned by AltaGas and assumed debt of $132.5 million and $5.9 million in transaction costs. The Taylor acquisition increased extraction capacity by 1,040 Mmcf/d, added 140,000 Bbls/d of transmission capacity, doubled extraction volumes produced to approximately 45,000 Bbls/d and increased the Field Gathering and Processing business capacity by 150 Mmcf/d.

In 2008 AltaGas invested $55 million to increase natural gas volumes and boost the efficiency at the Harmattan Complex and $12.6 million to upgrade the EDS pipeline. In 2009 AltaGas completed the addition of 10,000 Bbls/d of fractionation capacity at the Harmattan Complex for the processing of NGLs brought to the plant by truck.

On February 2, 2010, AltaGas offered to acquire all of the common shares of Landis Energy Corporation. On March 22, 2010 AltaGas completed the acquisition of Landis Energy Corporation for the aggregate purchase price of $25.6 million. As part of the acquisition, AltaGas acquired a 50 percent interest in the Alton Natural Gas Storage Project near Truro, Nova Scotia with a potential 10 Bcf of storage capacity.

In 2010 AltaGas entered into a long-term contract with a major natural gas producer to build and operate a 120 MMcf/d natural gas processing facility and associated gathering system in the Gordondale area of the Montney reserve area approximately 100 km northwest of Grande Prairie, Alberta. The plant will be equipped with liquids extraction facilities to capture the NGLs value for the producer. The plant is subject to regulatory approval and is expected to be in service in late 2012. AltaGas anticipates that early processing capabilities will be available by mid-2011 by using existing infrastructure in the area and building a pipeline to its Pouce Coupe facility.

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

In 2010 AltaGas completed expansions at the Pouce Coupe, Ante Creek and Acme gas processing facilities, adding a combined 32 Mmcf/d of capacity.

Development of the Power Business

In 2001 AltaGas entered the power business by purchasing 353 MW of power output from two coal-fired power generation units in the province of Alberta under long-term PPAs.

In 2004 AltaGas acquired 25 MW of gas-fired peaking capacity under a long-term capital lease arrangement.

In 2008 AltaGas installed 14 MW of gas-fired power generation capacity at the Bantry and Parkland field gathering and processing sites. In 2008 AltaGas acquired an effective 25 percent ownership interest in the 7-MW Boston Bar Limited

Partnership power plant and also acquired four run-of-river hydro development projects with total potential of approximately 50 MW.

In 2008 AltaGas acquired NovaGreen for approximately $38.5 million and the remaining 45 percent interest in GreenWing for $12.3 million. NovaGreen's name was changed to AltaGas Renewable Energy Inc. and GreenWing's name was changed to AltaGas Renewable Energy Limited Partnership.

In 2009 AltaGas acquired the 100-MW Glenridge wind development project located near Medicine Hat, Alberta. With the acquisition of GreenWing and Glenridge, AltaGas has a portfolio of 1,500 MW of mature and early development wind projects in western Canada and the northern and western United States.

In October 2009, the Bear Mountain Wind Park was commissioned at a cost of approximately $200 million. The 102-MW wind park comprises 34 turbines. The wind park was selected in 2006 as a successful bidder in the BC Hydro Fiscal 2006 Open Call for Power. Enercon GmbH, a leading turbine manufacturer based in Germany, provided and installed the turbines for the wind park under a fixed-price engineering, procurement and construction contract and operates and maintains the turbines under a long-term service agreement. AltaGas owns a 100 percent interest in the wind park.

In 2009 AltaGas invested $16.2 million to acquire approximately a five percent equity position in Magma Energy Corporation. Magma Energy Corporation currently owns and operates an 8-MW geothermal energy plant in Nevada as well as a portfolio of geothermal exploration and development projects in the western United States and South America. AltaGas received the right to acquire a direct interest in certain future geothermal projects developed or acquired by the company.

In 2010 AltaGas announced the signing of a 60 year Electricity Purchase Agreement with BC Hydro and ancillary long-term arrangements with the Tahltan First Nation in support of the Forrest Kerr 195 MW run-of-river hydroelectric project. The project is under construction and expected to be in service in mid-2014. This project is expected to add a significant stream of low-risk, long-life cash flow that supports AltaGas' objective of providing shareholders with stable and predictable cash flows. In addition to the Forrest Kerr project, AltaGas is developing the McLymont Creek and Volcano Creek run-of-river projects in the same area. The three projects have a combined generating capacity of approximately 277 MW.

AltaGas is pursing the installation of a 6-MW waste heat recovery unit near Sparwood, British Columbia. The project is supported by a 20-year Electricity Purchase Agreement with BC Hydro. Right-of-way and waste heat agreement discussions are underway with relevant parties and construction is expected to commence in 2011.

In 2010 AltaGas constructed a 15 MW cogeneration plant at the Harmattan facility. The 15-MW cogeneration facility provides the steam required for gas processing while providing clean base-load power to the Alberta power market.

Development of the Utility Business

In 2009 AltaGas offered to acquire the remaining outstanding common shares of Utility Group not already owned by AltaGas by way of a take-over bid. On October 9, 2009 AltaGas completed the acquisition of Utility Group for a purchase price of $75.2 million for the outstanding common shares of Utility Group, excluding those previously held by AltaGas or its affiliates and assumed $123.8 million in debt and $5.0 million in transaction costs. After the acquisition, Utility Group shares were delisted from the TSX. The Utility Group acquisition added three regulated businesses with more than 72,000 customers and infrastructure of over 20,000 km of pipelines. Utility Group holds an interest in the Ikhil Joint Venture which produces and supplies natural gas in Inuvik, Northwest Territories

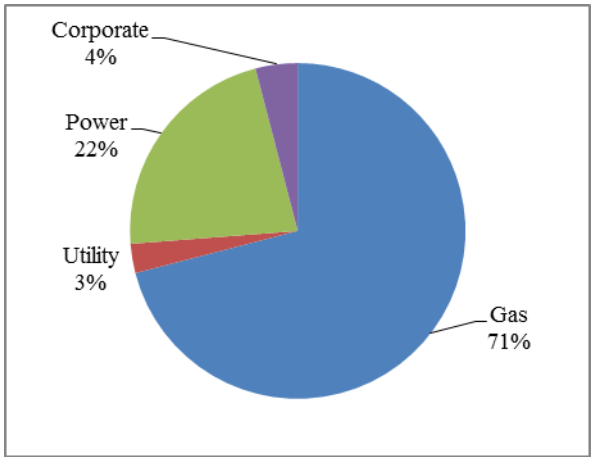
In November 2009 AltaGas acquired the 75.1 percent of the common shares not already owned by AltaGas and shareholder debt of Heritage Gas for $111.0 million including closing costs, bringing AltaGas' ownership of Heritage Gas to 100 percent.

In 2010 Heritage Gas completed a $19 million, 30 km natural gas pipeline construction project from the Halifax peninsula to Bedford, Nova Scotia. The expansion provides the foundation for further expansion into the growing communities in the Halifax Regional Municipality over the next several years.

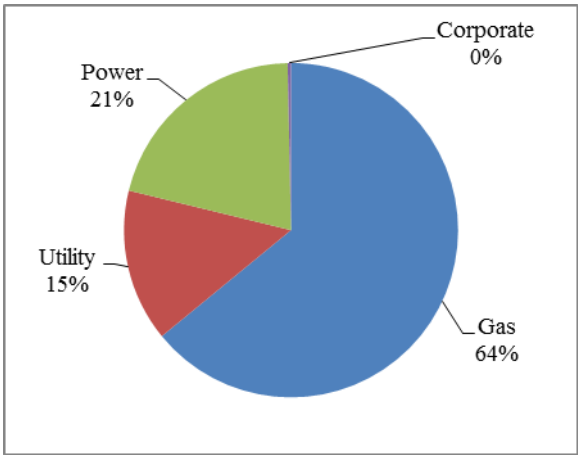
BUSINESS OF THE CORPORATION

AltaGas' net revenue for the 12-month period ended December 31, 2010 was $485.5 million compared to $456.6 million for the 12-month period ended December 31, 2009.

Net Revenue by Division for 2009 (1))2)



Net Revenue by Division for 2010 (1)(2)



Notes:

(1) Net revenue is gross revenue less the cost of sales.
(2) Before intersegment eliminations.

OPERATING DIVISIONS

Beginning with 2010, AltaGas has aggregated its business activities into three operating divisions; gas, power and utility. In the Gas division, business activities include extraction and transmission, field gathering and processing and energy services. The Power division consists of conventional coal-fired generation, gas-fired peaking plants and co-generation, wind power and hydroelectric. The Utility division comprises natural gas distribution. In addition, Corporate consists of opportunistic investments, risk management contract results and revenues and expenses not directly identifiable with the operating divisions.

GAS DIVISION

AltaGas' Gas Division contributed net revenue of $312.7 million for the year ended December 31, 2010, representing approximately 64 percent of AltaGas' total net revenue before intersegment eliminations.

GAS DIVISION – EXTRACTION AND TRANSMISSION

AltaGas' extraction business includes 100 percent ownership of the Harmattan Complex and JEEP, both in central Alberta, as well as interests in two extraction plants at Empress, Alberta, EEEP at Edmonton, Alberta and the Younger Extraction Plant in British Columbia. Also included in the extraction business is AltaGas' Bantry fractionation facility. AltaGas operates EEEP, JEEP, the Bantry field facility, Harmattan Complex and the Younger Extraction Plant. The extraction plants provide stable fixed-fee or cost-of-service type revenues and margin-based revenues. AltaGas' net raw gas licensed inlet capacity at these plants was 1,594 Mmcf/d at December 31, 2010.

The value of ethane and NGL extraction is a function of the difference between the value of the ethane, propane, butane and condensate as separate marketable commodities and their value as constituents of the natural gas stream. If the components are not extracted and sold at prices that reflect the value for each of the individual commodities, they are sold as part of natural gas and generate revenue for their heating value at the prevailing natural gas price.

In most cases the NGL recovered at natural gas processing and extraction plants in western Canada are delivered into a system of pipelines that collects and moves NGL to Fort Saskatchewan, Alberta or Sarnia, Ontario. NGL are used directly as an energy source and as feedstock for the petrochemical and crude oil refining industries. Ethane is the feedstock for ethylene production.

Extraction - Plant Fee Structures

Extraction facility owners have the right to extract liquids from the natural gas stream, either directly as the owner of the natural gas, or through NGL extraction agreements. The typical commercial arrangement involves the ethane and NGL extraction plant owner contracting with the gas shipper on a natural gas transmission system for the right to extract the ethane and NGL from the transporter's natural gas. By removing ethane and NGLs, the extraction plant is, in effect, extracting or shrinking a portion of the energy content of the shipper's natural gas. The extraction plant owner pays the transporter for the extracted energy or alternatively purchases a sufficient volume of natural gas from the market to replace the extracted energy, thereby keeping the transporter whole. This purchased gas is referred to as shrinkage or make-up gas.

Based on the results of the ERCB NGL Extraction Inquiry released in February 2009, the convention for obtaining extraction rights may change over the next three years, whereby the entitlement to the NGLs within the common-stream natural gas transported on Alberta-regulated gas transmission pipelines will be transferred to receipt shippers rather than the export delivery transporters. AltaGas is monitoring this development.

Extraction contract terms may be for firm or interruptible processing, and may vary from monthly to multi-year in length. Currently the majority of AltaGas' extraction agreements are multi-year term arrangements. AltaGas' share of all ethane production is sold through long-term, cost-of-service or fee-for-service arrangements that bear no commodity price risk. The sales price received under these contracts provides for a return on and of capital and the recovery of certain operating costs, including shrinkage gas attributable to that production. AltaGas' share of ethane production is sold at the outlet of the plants, with the product purchaser responsible for all downstream transportation and handling. AltaGas' ethane sales provide a stable, predictable cash flow base.

AltaGas' NGL production is sold under a variety of arrangements. At December 31, 2010, approximately 60 percent of AltaGas' NGL production was sold under long-term, fee-for-service contracts. These volumes do not bear any commodity price risk. The revenue from this portion of NGL sales provides a stable, predictable cash flow base.

On the portion of the NGL production that is not sold under long-term fee-for-service contracts, performance is subject to frac spread which is the price spread between NGLs extracted and the natural gas purchased to make up the heating value of the NGLs extracted. At December 31, 2010, approximately 40 percent of AltaGas' NGL production (13 percent of total extraction production) was sold under contracts subject to frac spread. If commodity prices or operating costs make NGL extraction uneconomical, the NGLs may be reinjected or the facilities may be turned down or shut-in. If this occurs, the operational flexibility of the commercial contracts translates into a minimal effect on margins.

Extraction – Plant Production

Extraction production is a function of natural gas volume processed, natural gas composition, recovery efficiency of the extraction plant and plant on-line time. The following table represents a summary of AltaGas' capacity and the production associated with extraction and fractionation plants in which AltaGas holds an interest:

Extraction or Fractionation Plant	Interest (%)[1]	AltaGas' Inlet Processing Capacity (Mmcf/d)[1]	2010 Liquids Production (Bbls/d)[2]		2009 Liquids Production (Bbls/d)[2]		Operated or Non-Operated
EEEP	48.667	190	NGLs	1,974	NGLs	2,149	Operated
			Ethane	5,260	Ethane	6,135	
Empress ATCO	7.2	79	NGLs	648	NGLs	611	Non-Operated
			Ethane	673	Ethane	623	
Empress Provident	11.25	135	NGLs	1,432	NGLs	1,488	Non-Operated
			Ethane	2,759	Ethane	2,730	
JEEP	100.0	250	NGLs	1,614	NGLs	1,763	Operated
			Ethane	4,236	Ethane	4,726	
Younger	56.667	425	NGLs	5,500	NGLs	5,113	Operated
			Ethane	8,207	Ethane	7,698	
Harmattan Complex	100.0	490	NGLs	921	NGLs	499	Operated
			Ethane	4,657	Ethane	5,009	
Bantry	100.0	25	NGLs	188	NGLs	157	Operated
Total[3]		**1,594**	**NGLs**	**12,276**	**NGLs**	11,780	
			Ethane	**25,792**	**Ethane**	26,922	

Notes:

(1) At December 31, 2010.
(2) Average volumes for the fourth quarter.
(3) Excludes field NGLs.

Extraction - Empress ATCO Extraction Plant

AltaGas' ownership interest in the Empress ATCO extraction plant was 7.2 percent at December 31, 2010. The remaining 92.8 percent interest in the facility is held by nine other owners with varying interests. AltaGas' ownership corresponds to a 79 Mmcf/d share of the plant's 1,100 Mmcf/d of natural gas inlet capacity.

The Empress ATCO plant, located on the Alberta-Saskatchewan border at Empress, Alberta is one of six extraction plants in the area. The Empress ATCO plant has two processing trains which provide the flexibility to easily manage production to reduce operating costs and operational risk, minimizing downside risk associated with fluctuating production volumes.

AltaGas is currently daily subscribed and processing gas under monthly and yearly arrangements. As there are five other extraction plants in the Empress area, there is considerable competition among the owners of the plants for producers' extraction rights.

Extraction - Empress Provident Extraction Plant

AltaGas acquired a 10 percent interest in the Empress Provident extraction plant in April 1998 and increased its share to 11.25 percent in December 2006. The plant, which began operations in September 1996, is located 2 km southeast of the Empress ATCO extraction plant.

The plant is licensed to process 1,200 Mmcf/d of natural gas, of which 135 Mmcf/d is AltaGas' share. AltaGas has managed its gas supply risk at this plant by securing 89 percent of inlet capacity on a long-term basis to ensure that its share of 135 Mmcf/d is fully utilized at all times.

AltaGas' ethane production is sold under a long-term, cost-of-service type contract that provides for the recovery of certain operating costs. Approximately 74 percent of AltaGas' share of propane plus production from this plant generates fixed-fee revenue plus reimbursement of associated operating costs under a long-term processing arrangement. The remainder is sold under a one-year evergreen marketing arrangement at the monthly market price for propane plus.

Extraction - Joffre Ethane Extraction Plant

AltaGas owns 100 percent of JEEP which has processing capacity of 250 Mmcf/d of natural gas and is capable of producing up to 10,400 Bbls/d of ethane and NGLs. The plant, which was constructed in 2002 at a net cost to AltaGas of $24.8 million for its initial 50 percent interest, started operations in December 2002. AltaGas operates the facility which is located at Joffre, Alberta.

The plant is adjacent to NOVA Chemicals Corporation's ("NOVA Chemicals") Joffre petrochemical complex and recovers ethane and NGLs from the fuel gas used at the complex. All ethane production from JEEP is sold under a long-term, cost-of-service type contract with NOVA Chemicals. Under this ethane sales agreement, a small portion of the operating cost risk is borne by AltaGas, based on the ratio of NGLs to total plant production. AltaGas sells its NGL production under a one-year evergreen marketing agreement based on the monthly average market price for NGLs.

Extraction – Edmonton Ethane Extraction Plant

AltaGas acquired a 48.67 percent interest in EEEP in August 2004 for $48.2 million, including an environmental liability of $5.0 million, for a net cash outlay of $43.2 million. The remaining interest in the plant is held by ATCO Midstream Ltd. AltaGas operates the plant. EEEP is directly connected to the Alberta Ethane Gathering System, and to BP Canada Energy Resources' Co-Ed NGL pipeline, providing safe and reliable outlets for the plant products.

The plant has a licensed gross inlet capacity of 390 Mmcf/d of natural gas and gross production capacity of specification ethane of 23,000 Bbls/d and NGLs of 7,500 Bbls/d.

A long-term gas supply contract provides a secure feedstock supply to EEEP. The processed gas from the facility supplies end-use markets in the city of Edmonton, Alberta. AltaGas' share of the plant products is sold under long-term contracts through cost-of-service or cost-plus sales arrangements.

Extraction – Younger Extraction Plant

AltaGas owns a 56.7 percent interest in the Younger Extraction Plant. The remaining interest is held by Provident. The Younger Extraction Plant, located at Taylor, British Columbia, processes natural gas transported on the Spectra Energy transmission system and Canadian Natural Resources Limited's Stoddart transmission system to recover NGLs.

The Younger Extraction Plant has 750 Mmcf/d of natural gas processing capacity. AltaGas' share of the natural gas processing capacity is 425 Mmcf/d and Provident's share is 325 Mmcf/d. AltaGas owns 100 percent of the facilities related to fractionation, storage, loading, treating or terminalling of NGLs. AltaGas operates the Younger Extraction Plant.

All of AltaGas' NGL production from the Younger Extraction Plant is sold to Provident under a long-term NGL purchase agreement which consists of a return on capital, recovery of operating costs, shrinkage make-up and a profit-share component. Provident sources gas supply to the Younger Extraction Plant as part of the NGL purchase agreement. AltaGas' ethane production is sold to Dow Chemicals under a long-term fee-for-service contract.

In 2010 AltaGas entered into an agreement to participate in the construction of an up to 250 MMcf/d natural gas pipeline to bring liquids rich gas from the Montney area of British Columbia to the Younger Extraction Plant. AltaGas will own 30% of the pipeline at an expected cost of $9 million. The pipeline is expected to be fully operational by the fourth quarter of 2011.

Extraction - Harmattan Complex

AltaGas owns a 100 percent interest in the Harmattan Complex located 100 km north of Calgary, Alberta. Harmattan has natural gas processing capacity of 490 Mmcf/d consisting of sour gas treating, NGL extraction and 35,000 Bbls/d of NGL fractionation and terminalling. Harmattan also has a 450 Bbls/d capacity frac oil processing facility, a 200 tonnes/d capacity industrial grade CO_2 facility and a 10,000 Bbls/d capacity NGL truck offload facility.

The Harmattan Complex extracts NGLs from the raw natural gas delivered for processing, fractionates the recovered NGLs into specification ethane, propane, butane and condensate, and provides storage and terminalling services for each product. The terminalling options for each product are:

Ethane – The Harmattan Complex is connected to the Alberta Ethane Gathering System by an interconnecting pipeline that is owned by AltaGas. All ethane produced at the Harmattan Complex is delivered to the Alberta Ethane Gathering System.

Propane – Producers may have their propane loaded onto either rail or truck. The propane truck and rail loading facilities, which are located at Didsbury, Alberta, are connected by pipeline to the main complex.

Butane and Condensate – Producers may have their butane and condensate delivered to either the Rangeland or Cremona pipeline or loaded onto trucks at the Harmattan Complex.

At the Harmattan Complex, natural gas processing services are provided to approximately 60 producers under contracts with a variety of commercial arrangements and terms. Fee-for-service revenues are generated from the raw natural gas processing, NGL extraction, fractionation and terminalling, and custom NGL processing. Fee-for-service means that fees are charged to the customer for the service provided on a per unit volume basis.

Approximately 35 percent of the natural gas volume processed at the Harmattan Complex is done under the terms of the Rep Agreements which have life-of-reserves dedications. In addition to the natural gas processed under the Rep Agreements, a further 25 percent of the natural gas currently being processed at the Harmattan Complex is committed for over three years with annual minimum volume obligations. The balance of the raw natural gas processed at the Harmattan Complex is processed under contracts with terms varying from one month to life-of-reserves. The majority of the contracts provide for fee escalation based on the Canadian Consumer Price Index.

Under the terms of many of the raw natural gas processing agreements, a component of the compensation received by AltaGas for providing services to the producers is derived by AltaGas having the right to purchase a portion of the producers' ethane, propane, butane and condensate for a price equal to the value of the equivalent natural gas. This commercial arrangement is known as product-in-kind.

The profitability of product-in-kind arrangements is a function of the difference between the value of specification ethane, propane, butane and condensate and the value of NGLs if they remain in the natural gas. The ethane acquired by AltaGas under the product-in-kind arrangements is sold under a long-term contract for a price that includes full recovery of the cost of acquiring the ethane from the producers plus a premium. The propane, butane and condensate volumes acquired by AltaGas are sold into the Alberta market at prevailing prices.

AltaGas has received approval from the ERCB to construct the Harmattan Co-Stream Project which will allow the extraction of NGLs from gas in the NGTL western Alberta system using unused capacity in the NGL recovery units at Harmattan. AltaGas has entered into a processing agreement with NOVA Chemicals related to ethane and NGL extraction at Harmattan as part of the proposed Harmattan Co-Stream Project. The processing agreement between AltaGas and NOVA Chemicals is for an initial term of 20 years. AltaGas will deliver all NGLs or co-stream gas products on a full cost-of-service basis to NOVA Chemicals. The agreement provides that all capital expenditures and operating costs related to the proposed project be fully recovered through fees under normal operations. Construction is expected to commence early in 2011 with plant start-up expected in the first quarter of 2012.

Extraction - Bantry Field Fractionation Facility

AltaGas purchased the Bantry natural gas processing plant in May 2000 and expanded it in 2001. The plant, operated by AltaGas, is equipped with fractionation facilities capable of producing up to 400 Bbls/d of specification propane, butane and pentanes-plus for sale to local markets at market prices. Fractionation services at Bantry are provided at a rate per cubic meter of product processed.

Extraction – Competition

AltaGas' extraction assets are well positioned to operate in a competitive environment and take advantage of their strategic locations and contract terms in order to compete in the NGL industry.

Competition exists for AltaGas' Empress ATCO and Empress Provident extraction facilities as there are six extraction plants in the Empress area, resulting in significant competition for natural gas supply. AltaGas' Empress plants mitigate this risk by utilizing long-term natural gas supply contracts and by accessing gas supply through its Energy Services business.

AltaGas' JEEP and EEEP facilities are strategically located and take advantage of the gas consumption by the petrochemical industry and the City of Edmonton, respectively.

The Younger Extraction Plant processes natural gas produced in the Fort St. John basin located in northeast British Columbia. This facility is strategically located as the only straddle extraction plant in this area of British Columbia. While the Younger Extraction Plant is the only straddle extraction plant in the area, the Alliance pipeline competes for local natural gas supply.

The Harmattan Complex is well-positioned as the high-volume, low-cost processing facility in its service area. The Harmattan Complex is a significant service provider with a large capture area in west central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and increase asset utilization and profitability. The Harmattan Co-Stream Project is expected to increase utilization at the plant.

Transmission – Business Description

AltaGas owns five natural gas transmission systems with transportation capacity of approximately 554 Mmcf/d and three NGL pipelines with combined capacity 151,600 Bbls/d.

The following table provides a summary of the gross capacity of AltaGas' transmission pipelines at December 31, 2010. The majority of the transmission pipeline transportation contracts are fixed-fee or transport-or-pay.

Transmission Pipeline	Product	Area	Ownership (percent)	Operating Capacity	Length (km)	Operated/ Non-operated[(1)]
Battle Lake	natural gas	Central Alberta	100.0	15 Mmcf/d	16	Operated
Cold Lake	natural gas	East central Alberta	99.2	80 Mmcf/d	253	Operated
Kahntah	natural gas	Northeast British Columbia	100.0	35 Mmcf/d	55	Operated
Suffield	natural gas	Southeast Alberta	100.0	400 Mmcf/d	243	Operated
Summerdale	natural gas	Central Alberta	100.0	24 Mmcf/d	18	Operated
Porcupine Hills	NGL	Southwest Alberta	100.0	11,600 Bbls/d	164	Operated
EDS	NGL	Central Alberta	100.0	90,000 Bbls/d	180	Operated
JFP	NGL	Central Alberta	100.0	50.000 Bbls/d	180	Operated

Note:

(1) AltaGas operates the Cold Lake pipeline and has subcontracted out the operator function at its other pipelines.

Transmission – Suffield

The Suffield natural gas transmission system consists of two natural gas pipelines which transport natural gas produced in and around the Suffield military block in south eastern Alberta to the TransCanada Pipelines mainline at Burstall, Saskatchewan. The Suffield system is regulated by the National Energy Board and rates on the system are based on a market-based tolling methodology. The two pipelines have 400 Mmcf/d of combined transmission capacity. The south Suffield pipeline is a 147-km pipeline of six to 16-inch diameter pipe and the north Suffield pipeline is 96 km of 16-inch diameter pipe.

The majority of the Suffield system's capacity is currently contracted by Cenovus Energy Inc. ("Cenovus") through transport-or-pay and volume commitments that will expire in 2022 and be renewable for one-year periods thereafter. Volume commitments decline annually from 406,000 GJ/d in 2010. On the Suffield system Cenovus pays AltaGas based on a daily contract quantity. To the extent that annual volumes shipped are less than the annualized daily contract quantity, AltaGas does not refund the shipper for payments made under the daily contract quantity but posts the shortfall quantity to a shortfall account as a credit until such time as the shipper reduces the shortfall by delivering excess quantities or until the shortfall amounts expire.

Transmission – EDS and JFP

The EDS is used to transport ethylene, the main product produced by the NOVA Chemicals Joffre petrochemical complex, to industrial customers and storage facilities in the Edmonton and Fort Saskatchewan areas of Alberta. The EDS is an 180-km, 12-inch diameter pipeline with capacity of 90,000 Bbls/d. The JFP transports NGLs from Fort Saskatchewan to the NOVA Chemicals Joffre petrochemical complex. The JFP is an 180-km, 10-inch diameter pipeline with capacity of 50,000 Bbls/d.

The EDS transportation agreement has an initial term of 12 years to 2016 with provisions for extensions thereafter. The payments made to AltaGas by NOVA Chemicals for transportation services are the sum of a fixed, transport-or-pay fee plus the full recovery of actual costs incurred in operating EDS. The fixed-fee is subject to an interest rate adjustment every three years based on then-current interest rates. The EDS transportation agreement also contains provisions that

define the incremental fees that will be charged to NOVA Chemicals in the event that additional capital is invested by AltaGas in the system. The termination of the EDS transportation agreement at the end of the initial 12-year term requires five years' notice by NOVA Chemicals. After the initial term, the notice period to terminate is three years. NOVA Chemicals has the option to purchase the pipeline after the initial term on three years' notice at a price based on a 30-year straight-line depreciation, subject to a floor price. NOVA Chemicals cannot selectively renew only the EDS transportation agreements; the termination of the EDS transportation agreement requires the termination of the JFP transportation agreement. The terms of the JFP transportation agreement are essentially identical to the terms in the EDS agreement. NOVA Chemicals cannot selectively renew only the JFP transportation agreement; the termination of the JFP transportation agreement requires the termination of the EDS transportation agreement.

Transmission – Porcupine Hills

The Porcupine Hills pipeline in southwest Alberta is a single-shipper condensate pipeline. The Porcupine Hills condensate pipeline delivers condensate from the Shell Waterton plant to the Town of Turner Valley for Shell Canada. In 2010, the Porcupine contract was renegotiated and extended to March 31, 2015 with an option to renew annually thereafter.

Transmission – Cold Lake, Kahntah, Summerdale and Battle Lake

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 39 receipt points and 36 delivery points (including four pipeline interconnects). The majority of the capacity on the Cold Lake system is contracted to AltaGas' Energy Services business which markets or exchanges most of the gas on the Cold Lake system. The Kahntah pipeline was constructed to transport natural gas from British Columbia to Alberta. Due to lower producer volumes and reduced drilling activity in the area the Kahntah transportation agreement terminated on March 31, 2010. The Kahntah pipeline is being taken out of service until gas prices recover and gas production in the area recommences, providing opportunities to extend the life of this asset. The Summerdale pipeline capacity is contracted to AltaGas' Energy Services business to enable that business to optimize marketing and exchange opportunities. The Battle Lake pipeline capacity is contracted to several shippers under agreements that are extended annually.

Transmission – Competition

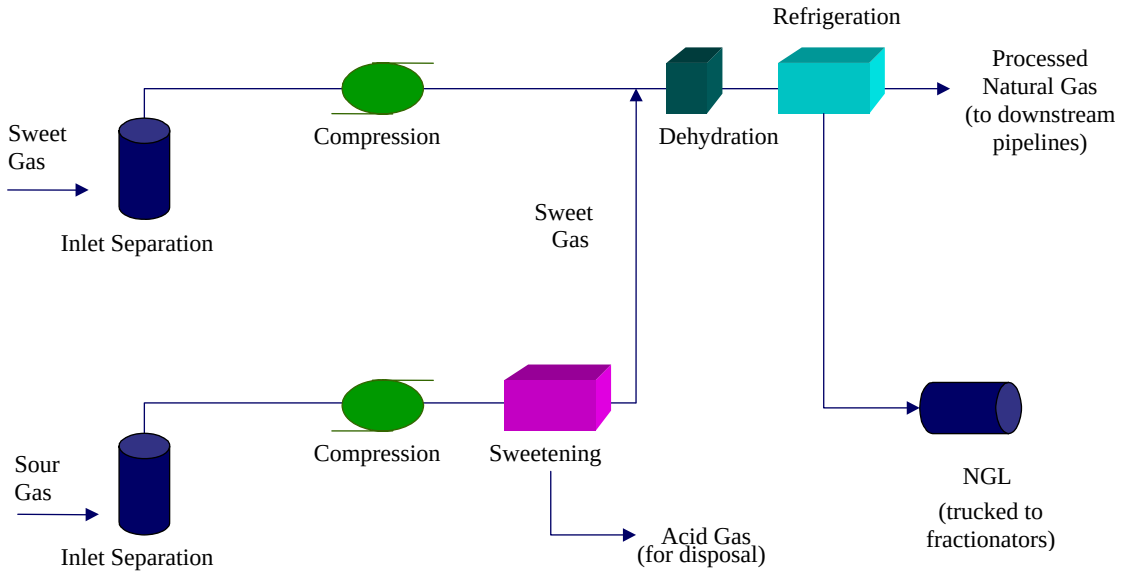
AltaGas competes with other midstream entities operating in the WCSB. AltaGas' transmission assets are well positioned to operate in a competitive environment and take advantage of their strategic locations and contract terms in order to compete with others. AltaGas continually investigates new pipeline opportunities in developing areas and in the vicinity of other AltaGas assets.

GAS DIVISION – FIELD GATHERING AND PROCESSING

The Field Gathering and Processing business consists of over 70 gathering and processing facilities in 31 operating areas located in western Canada and approximately 6,500 km of gathering lines upstream of processing facilities that deliver natural gas into downstream pipeline systems that feed North American natural gas markets. AltaGas has a total gross licensed processing capacity of 1.2 Bcf/d, of which one-third is capable of processing sour gas. AltaGas operates all but three of its facilities.

The gathering systems move natural gas on behalf of producers from the wellhead to AltaGas processing facilities where impurities and certain hydrocarbon components are removed and the gas is compressed to meet the operating specifications of downstream pipeline systems that deliver gas to domestic and export energy markets. Field Gathering and Processing's main business drivers are throughput, gathering and processing fees and operating costs. Throughput is impacted by new well tie-ins, reactivations, recompletions, well optimizations performed by producers and natural production declines in areas served by AltaGas' processing facilities.

Field Gathering and Processing – Typical Field Gas Processing Plant



Raw natural gas produced at the wellhead is a mixture of methane and other hydrocarbon components and impurities, including water vapour, carbon dioxide and hydrogen sulphide. Raw gas with amounts of hydrogen sulphide in excess of downstream pipeline specifications is considered sour. All other gas is considered sweet. Sour gas goes through more extensive processing – known as sweetening – in order to remove the hydrogen sulphide and ensure that the gas meets pipeline specifications. All natural gas must be processed through a natural gas plant to remove impurities and the various hydrocarbon components before the natural gas is delivered via downstream pipelines for ultimate sale and consumption. The amount and complexity of processing required before the raw gas is of saleable quality is a function of the quantity of NGLs and impurities present in the raw gas stream.

The raw natural gas is first gathered from the wellhead through natural gas gathering systems, and then delivered to and processed through a natural gas processing plant. The design of a natural gas processing plant is determined by the composition of the raw gas that it is intended to process. Natural gas that contains minimal or no amounts of NGLs or other elements will bypass certain processes within a typical natural gas plant configuration.

Raw natural gas entering the natural gas plant is subject to inlet separation where free water and any free NGLs are separated from the natural gas stream. If the natural gas is sour, it is sweetened by the removal of hydrogen sulphide. The natural gas is then usually dehydrated to remove any remaining water. If significant NGLs are still present in the sweet gas they are removed to meet downstream pipeline specifications. NGLs generally have greater value if extracted in liquid form and additional NGL recovery beyond downstream pipeline specifications may be carried out in order to capture the value of the NGLs. This additional recovery process can be done at field gas plants or at large-scale extraction plants. See "Gas Division – Extraction and Transmission". AltaGas has NGL extraction capability at 30 of its natural gas field processing facilities.

The remaining processed gas exiting the natural gas plant is delivered to the downstream transportation pipeline for eventual distribution to end-use markets. NGLs must be further processed (fractionated) into their individual components: propane, butane and pentanes-plus. The NGLs may be fractionated on site or trucked or pipelined to fractionation facilities.

Field Gathering and Processing - Facilities

AltaGas' Field Gathering and Processing business generates revenue from fees for volumes of natural gas processed at a processing facility or gathered through a gathering system.

AltaGas strives for continued improvement, operational excellence, and maximum utilization of all facilities over which it has operational control and to consistently exceed WCSB average utilization rates. Volume additions at facilities, which come from new well tie-ins and from reactivations, re-completions and well optimizations performed by producers, are offset by natural production declines. The focus on skid-mounted facilities allows AltaGas to redeploy these assets in response to producer processing requirements, thereby increasing processing volumes, profitability and utilization.

Field Gathering and Processing Facility Capacity and Throughput

	2010	2009
Capacity (gross Mmcf/d)[(1)(2)]	1,191	1,172
Throughput (gross annual Mmcf/d)[(2)]	423	453
Capacity utilization (%)	35	39

Notes:

(1) As at December 31.
(2) Gross numbers are before and are not adjusted to reflect AltaGas' working interest.

There were an estimated 4,960 natural gas well completions in the WCSB for 2010. Total marketable gas production in the WCSB is currently estimated at approximately 14 Bcf/d. Average facility utilization declined to 36 percent in 2010 from 39 percent in 2009. AltaGas experienced declining throughput primarily due to lower drilling activity and natural declines. Producer activity was impacted by low commodity prices. While current relatively low natural gas prices are expected to persist into 2011, AltaGas expects demand for gathering and processing facilities will grow in 2011 as natural gas producers focus on drilling liquids rich gas and the associated gas from the higher level of oil targeted drilling in the WCSB.

Field Gathering and Processing - Significant Operating Areas

AltaGas' facilities are often physically linked, creating facility complexes that offer delivery options and revenue continuity in the event that one of the plants in a complex shuts down. With over 70 processing facilities in 30 operating areas, AltaGas' Field Gathering and Processing business is not dependent on any one facility or operating area.

Field Gathering and Processing - Customers

In 2010 AltaGas conducted business with more than 260 customers in its operating areas, with no customer representing more than 6 percent of Field Gathering and Processing net revenue. The Field Gathering and Processing business's top 10 customers represented approximately 7 percent of consolidated net revenue for 2010.

Field Gathering and Processing - Contracts

AltaGas gathers and processes natural gas under contracts with natural gas producers. There are approximately 1,400 active gathering and processing contracts. These contracts, in general:

- Establish fees for the gathering and processing services offered by AltaGas;
- Define the producers' access rights to gathering and processing services;
- Establish minimum throughput commitments with producers and use appropriate fee structures to recover invested capital early in the life of the contract where capital investment is required by AltaGas;
- Define the terms and conditions under which future production is processed at an AltaGas facility; and
- Seek to recover operating costs to mitigate the impact of volume declines.

The amount of capital that AltaGas commits to acquiring or developing gathering and processing facilities is linked to AltaGas' assessment of the production available to be processed at the facility, reserves in the area, the extent of the reserve dedication and the processing fees to be paid by producers for its services. When a facility is acquired, AltaGas conducts an independent review of the natural gas reserves and production in the area surrounding each facility using, among other sources, ERCB production data and reserve estimates and producers' reserve reports for the area. AltaGas also conducts a review of the physical plant and equipment and the operating and maintenance costs for each facility.

Fee Structure

In determining appropriate contractual provisions, including a reasonable payback period on its invested capital, AltaGas seeks to align its interests with the financial and business objectives of its producer customers. The vast majority of AltaGas' gathering and processing contracts are volumetric service fee structures, based on a rate per Mcf of throughput. Volumetric fee structures may include a provision for recovery of actual operating costs, which further mitigates the financial risk related to volume variability. Operating costs recovery in 2010 was approximately 40 percent compared with 40 percent in 2009. In addition, approximately 78 percent of contracts in place at December 31, 2010 were subject to annual price escalation related to changes in the Consumer Price Index. This toll-for-service structure (as opposed to the commodity spread-based price structures predominantly used by midstream companies in the U.S.) avoids exposure to commodity price risk as revenue is a function of volumes processed. AltaGas' investment is generally protected by the

life of reserves behind the facility, since producing wells typically remain connected to a gathering and processing system for their entire productive lives.

AltaGas may underpin capital commitments through the use of one or more of the following contractual provisions:

Take-or-Pay: Take-or-pay arrangements are designed to ensure AltaGas recovers its invested capital in a relatively short period of time. This is achieved by producers providing minimum volume or capital recovery commitments to AltaGas. With minimum volume commitments the producer must process a specified volume at a rate per Mcf over a specified period of time or pay any revenue shortfall. The sum of the processing revenue provides AltaGas with a return on and of capital within a specified period. Risk is limited to counterparty creditworthiness. In recent years, AltaGas' strategy has shifted to minimum monthly volume commitments to decrease credit risk and lead to predictable cash flow.

Capital and Operating Cost Recovery: The producer pays two distinct fees to AltaGas, one to provide a return of and on capital and the other to cover AltaGas' operating costs. Return of and on capital is made more certain by reducing the risk of unexpected operating costs. Risk is largely limited to the timing of production.

Area of Mutual Interest: When AltaGas acquires a facility the vendor is typically the largest producer using that facility. As a result, AltaGas is usually entitled to gather and process the majority of the natural gas production associated with the facilities it acquires due to its reserve dedication contracts, thus reducing the possibility of competitive plants being built in the same area. Risk is largely limited to the timing of production. The contract terms also ensure any future production brought on stream in a specified area must flow to an AltaGas facility. Future natural gas throughput is generally secured by contractually committing the vendor of the facility to dedicate any future production from specified reserves or future areas of development surrounding the facility.

Geographic Franchise with Economic Out: Contractual provisions allow AltaGas to terminate or renegotiate a contract if it is not economical to continue processing. Risk is largely limited to the timing of production and operating cost efficiencies.

Length of Term

Where natural gas reserves have been dedicated under contract, the contract normally extends beyond one year and up to the life of the reserves, depending on the amount of capital AltaGas has invested in the facility. Where reserves have not been dedicated under contract or AltaGas has not made a significant capital investment, the contracts are normally subject to termination by either party upon one to three months' notice. As mentioned previously, producing wells typically remain connected to a gathering and processing system for their entire productive lives.

Type of Service

In general, producers have access to either firm service or interruptible service. Firm service offers producers priority to have their natural gas processed at the applicable AltaGas facility subject to industry standard maintenance and force majeure. Interruptible service is available only if the applicable AltaGas facility has capacity available after all firm service commitments with respect to such facility have been satisfied. Firm service is normally provided to a producer when the producer's natural gas reserves have been dedicated to an AltaGas facility.

Field Gathering and Processing - Operating and Maintenance Expenses

Operating and maintenance expenses for gathering and processing facilities generally include: (i) labour costs for operations and maintenance staff; (ii) materials consumed in processing or maintenance, including chemicals and lubricants; (iii) land lease costs; (iv) property taxes; (v) fuel and power costs; and (vi) other overhead costs. For the plants operated by AltaGas, the most significant expenses are labour, utilities, property taxes and repairs and maintenance. Repairs and maintenance are scheduled, where possible, to minimize down time and coordinate with producers' well maintenance activities. One of AltaGas' strategies is to increase the number of contracts with flow-through operating costs provisions.

Field Gathering and Processing - Competition

AltaGas competes with other midstream entities operating in the WCSB. In 2010 AltaGas processed an average of 422 Mmcf/d, which was approximately 3 percent of volumes produced in the WCSB. The majority of processing capacity generally continues to be provided by the upstream natural gas exploration and production companies.

The field gathering and processing marketplace continues to evolve and the competitive environment also continues to change. AltaGas believes that its field gathering and processing strategies and competitive advantages will continue to allow it to effectively compete in the midstream marketplace. AltaGas also believes that its operational skills and market penetration make it a preferred business partner for many exploration and production companies.

GAS DIVISION – ENERGY SERVICES

The Energy Services business consists of an energy management business and a gas services business.

Energy Management

The energy management business consists of providing energy consulting and supply management services and arranging natural gas and power supply for non-residential end-users. AltaGas' energy management services are provided under the brand name ECNG Energy and are supported by employees in: Burlington and Chatham, Ontario; Calgary, Alberta; and Vancouver, British Columbia.

The majority of the energy management fee-for-service revenue is based on one-to-three-year evergreen contracts. Fees are earned by providing advisory services, and arranging and managing supply on behalf of customers. These services allow customers to reduce exposure to gas and power price volatility and to match their energy supply arrangements with their risk and budget objectives.

In the energy management business, AltaGas primarily enters into agency retainer agreements with clients under which it provides natural gas and electricity supply and price management advice to its customers. Under these agency agreements AltaGas, on behalf of its end-use customers, also purchases, manages and fixes the price of the client's natural gas and electricity purchases. AltaGas acts as agent on behalf of its customers and is generally not exposed to changes in the commodity prices.

Gas Services

One of the key functions of the Energy Services business is to support AltaGas' infrastructure businesses. The gas services group contracts supply and shrinkage gas for AltaGas' extraction facilities. It also contracts and resells capacity on AltaGas' transmission pipelines and provides natural gas control services to balance natural gas flows. Gas services markets natural gas for Field Gathering and Processing customers and in the process earns margins, manages credit exposure, and provides additional value-added services to AltaGas' producer customers. Gas services also contracts and manages natural gas supply for AltaGas' gas-fired peaking plants.

In addition to supporting the other operating segments within AltaGas, the gas services business identifies opportunities to buy and resell natural gas, market natural gas for producers and exchange, reallocate or resell pipeline capacity and storage to earn a profit. Net revenues from these activities are derived from low-risk opportunities based on transportation cost differentials between pipeline systems and differences in natural gas prices from one period to another. Fixed margins are earned by simultaneously locking in buy and sell transactions in compliance with AltaGas' credit and commodity risk policies. AltaGas also provides energy procurement services for large industrial and utility gas users and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

AltaGas' gas services business also includes transportation arrangements into eastern Canadian markets and within Alberta in the form of gas exchange arrangements. AltaGas markets or exchanges all of the volumes that flow through its Cold Lake and Summerdale pipeline systems. In a gas exchange transaction AltaGas receives natural gas from customers on an AltaGas system and delivers the gas to its customers on the TransCanada, ATCO or TransGas systems. By purchasing or exchanging gas on these pipeline systems and at other facilities, AltaGas has achieved positive margins while providing improved netbacks for producers.

The gas services business manages AltaGas' 50 percent share of Sarnia Airport Storage Pool Limited Partnership, which owns 5.3 Bcf of gas storage capacity. This facility became commercially operational on June 26, 2009. AltaGas is seeking to optimize value with gas inventory in storage. Market Hub Partners Management Inc., an affiliate of Spectra Energy Corp., has been contracted to manage the general partner of the limited partnership and operate the facility.

Energy Services - Customers

AltaGas energy management and gas service customers are commercial, industrial, agricultural and institutional end-users in Ontario, Alberta, British Columbia, Quebec, New Brunswick, Nova Scotia and Manitoba. Customer retention rates are over 92 percent. The AltaGas energy management business arranges natural gas and electricity supply on behalf of its customers through an array of qualified suppliers, including AltaGas.

In its gas services business, AltaGas buys natural gas from a wide array of suppliers including wholesale marketing companies and producers and sells natural gas to other wholesale marketing companies and commercial and industrial end-users.

No Energy Services customer represented more than 10 percent of consolidated revenue during 2010.

Energy Services - Competition

In the energy management business, AltaGas competes with other marketing and consulting firms. In the gas services business, AltaGas' competitors range from single person operations to large marketing and aggregation companies. The primary source of competition is the marketing arms of large oil and gas producers.

POWER DIVISION

AltaGas' Power Division contributed net revenue of $101.8 million for the year ended December 31, 2010, representing approximately 21 percent of AltaGas' total net revenue before intersegment eliminations.

The Power business is engaged in the sale of electricity and ancillary services in the Alberta wholesale market and the sale of electricity in British Columbia to BC Hydro. At December 31, 2010, AltaGas had 509 MW of installed power capacity, comprised of 353 MW of power generation capacity through a 50 percent ownership interest in the Sundance B PPAs, a capital lease for 25 MW of gas-fired peaking capacity, another 14 MW of gas-fired peaking capacity and 15 MW of cogeneration capacity in Alberta and 102 MW of wind power generation capacity in British Columbia. AltaGas also has an effective 15 percent interest in a 7-MW run-of-river hydroelectric generation facility in British Columbia.

At December 31, 2010, AltaGas' 407 MW of installed power capacity in Alberta served approximately 5 percent of Alberta's power demand. The 102-MW Bear Mountain Wind Park is the first wind generation facility in British Columbia. The 195-MW run-of-river Forrest Kerr hydroelectric project is currently under construction, with the camp complete. Civil works commenced in February 2011 and tunnelling activities are expected to begin in late March 2011. Commercial operations at Forrest Kerr are expected to begin in July 2014.

Additional growth in the Power business is expected to occur by advancing AltaGas' significant and growing portfolio of renewable energy projects and pursuing further cogeneration opportunities. AltaGas has approximately 1,900 MW of wind and run-of-river hydroelectric projects under development. The renewable power portfolio consists of 1,500 MW of wind projects, 500 MW in Canada and 1,000 MW in the northern and western United States. The hydroelectric portfolio under development consists of approximately 205 MW in British Columbia.

Power Purchase Arrangements - Alberta

PPAs were established in 1999 under Alberta's program of power industry deregulation. PPAs were created to separate ownership of the physical power generation assets from control of output.

ASTC Power Partnership

AltaGas and TransCanada are partners in the ASTC Partnership. Each partner owns a 50 percent share of ASTC Partnership and contributed 50 percent of the $223.1 million required for the ASTC Partnership to purchase the two Sundance B PPAs from Enron Canada Power Corporation on December 28, 2001. There are two Sundance B PPAs, one for each of Units 3 and 4 at the Sundance Plant. The ASTC Partnership holds the Sundance B PPAs as partnership property, with both partners having an equal interest in each PPA.

The indirect 50 percent interest in the Sundance B PPAs provides AltaGas with the rights to 353 MW of coal-fired generation capacity, as well as to ancillary services from Sundance Units 3 and 4, until December 31, 2020.

The ASTC Partnership started dispatching power effective December 29, 2001. AltaGas maintains the books and records of the ASTC Partnership, including providing accounting services. TransCanada manages daily operations, including the dispatch of power into the Pool. AltaGas and TransCanada are each responsible for managing the market risk associated with their individual shares of the power generation capacity.

The Sundance B Plant

TransAlta owns the coal-fired Sundance Plant, which is located approximately 70 km west of Edmonton, Alberta. The Sundance Plant consists of Units 1 through 6. An auction conducted on August 24, 2000 grouped the units into three plants: Sundance A Plant - Units 1 and 2, Sundance B Plant - Units 3 and 4, and Sundance C Plant - Units 5 and 6. Sundance B Plant has been operating since 1976 (Unit 3) and 1977 (Unit 4).

The Sundance Plant is connected to the Alberta Interconnected Electric System, which allows access to markets in Alberta, British Columbia, Saskatchewan and the United States.

The Sundance B Plant - Power Sales

Revenue from the sale of power is largely driven by target availability, hedge prices (for the portion of capacity that is hedged) and Pool prices (for the portion of capacity that is not hedged). The inter-relationship of production, Pool prices and cost of sales is specified in the PPAs. Generally, the ASTC Partnership will be compensated when power production is less than target levels, at a rate based on the previous 30-day average Pool price, as described in more detail later in this section. AltaGas recognizes its share of revenue based on target production levels, with any increase or decrease relative to target credited or charged to cost of sales.

Under the Sundance B PPAs, the ASTC Partnership holds the rights to the power capacity and ancillary services from Units 3 and 4 of the Sundance Plant. Day-to-day operation requires the ASTC Partnership to communicate the volume of power available and the price of the power to the AESO. The ASTC Partnership is obligated to pay TransAlta a price which contributes to TransAlta's capital and operating costs as determined by formulas in the Sundance B PPAs. The majority of the ASTC Partnership's cost of sales is the fixed costs and variable operating costs paid to TransAlta and the variable costs of transmission and Pool trading charges.

Each of Units 3 and 4 has a contracted capacity of 353 MW. In September 2007, TransAlta increased the capacity of Unit 4 by 53 MW pursuant to their rights under the PPA. TransAlta provided all of the capital, is responsible for all operating costs and is entitled to all benefits associated with this increased capacity, although ASTC earns a fee associated with the administration of the agreement. The Sundance B PPAs recognize that the plants will not produce at 100 percent capacity all of the time. TransAlta is obligated to provide AltaGas financial compensation if actual generation of electricity from Units 3 and 4 falls below a specified target level, which was 86 percent of contracted capacity in 2010. This is accomplished by a monthly payment based on the difference between actual availability and target availability, multiplied by RAPP. Similarly, if Units 3 and 4 produce above target, then ASTC is obligated to pay TransAlta based on the difference between actual availability and target availability, multiplied by RAPP. ASTC pays transmission charges based on actual power delivered. During these under or over-generation periods AltaGas has financial exposure to the difference between the Alberta spot price and RAPP on the difference between volumes generated and target availability. The financial exposure may be positive or negative depending on the difference between the current Pool price and RAPP.

TransAlta is an experienced operator of coal-fired electrical generation facilities and has financial incentives to operate the Sundance B plant efficiently and at high levels of electricity generation. The plant uses coal from the adjacent Highvale Mine, which is anticipated to have sufficient reserves for the expected fuel requirements of the Sundance B Plant beyond the life of the Sundance B PPAs. The coal price formula, which is pre-defined in the PPAs, is subject to inflationary indices and is not linked to current market prices for coal.

The following chart provides a summary of power prices and volumes for the last two years.

Power Prices and Volumes	2010	2009
Volume of power sold (GWh)[(1)]	2,828	2,725
Average price received on the sale of power ($/MWh)[(1)]	66.79	68.97
Alberta Power Pool average spot price ($/MWh)[(1)(2)]	50.76	47.84

Note:

(1) Annual average.
(2) Includes only Alberta volumes and prices realized on the sale of power.

Gas-Fired Peaking Capacity

On September 1, 2004 AltaGas entered into a long-term capital lease with Maxim Power Corp. for 25 MW of gas-fired peaking capacity on four sites in southern Alberta. The capital lease has a 10-year term that commenced September 1, 2004 and includes an option at the end of the initial term to extend the term for 15 years or to purchase the assets. The capital lease requires AltaGas to pay a monthly capacity fee. The operations and maintenance services contract that previously dealt with the peaking facilities expired March 15, 2007 and AltaGas assumed responsibility for operation of the facilities. AltaGas retains 100 percent of the ancillary services and merchant peaking sales revenue.

In 2008 AltaGas installed an additional 14 MW of gas fired peaking generation at the Bantry and Parkland field gathering and processing facilities.

In Alberta, gas-fired peaking capacity generally provides energy during times of high prices or supplies operating reserves that can be used during system contingencies. AltaGas manages the gas requirement and dispatches the units.

This gas-fired power capacity provides fuel diversity to AltaGas' power business, provides increased operational flexibility and partial backstopping to outages at Sundance.

Harmattan Cogeneration

Late in 2010, AltaGas commissioned a 15 MW cogeneration facility at the Harmattan gas plant. The facility consists of a gas turbine which drives a 15 MW generator for delivery of electricity into the Alberta Power market, as well as a heat recovery steam generator that is capable of producing all of the steam required to process gas at Harmattan from the waste heat in the exhaust gases from the turbine. Cogeneration is an efficient, environmentally responsible means of producing electricity and is an attractive area of potential growth for AltaGas' power business.

Wind Power Generation

In October 2009, AltaGas completed construction of the 102-MW Bear Mountain Wind Park near Dawson Creek in British Columbia. The Bear Mountain Wind Park consists of 34 turbines, a substation and transmission and collector lines. It is connected to the British Columbia Transmission Corporation's (now BC Hydro) transmission grid. The turbine manufacturer, Enercon GmbH of Germany, provides operating and maintenance services to BMWLP under a long-term service agreement.

All of the power from the Bear Mountain Wind Park is sold to BC Hydro under a 25-year Electricity Purchase Agreement at a set price which increases annually by 50 percent of Canadian Consumer Price Index. BMWLP has retained the green attributes and renewable energy credits and intends to sell them to provide an additional revenue stream.

Bear Mountain Wind Park is owned 100 percent by AltaGas. There are royalty agreements in place with Peace Energy Cooperative (a community-based group) and Aeolis Wind Power Corporation for a total of 0.912 percent of the project revenues and for 28.5 percent of any revenues from the sale of greenhouse gas credits above a cumulative threshold amount.

In August 2008 AltaGas acquired the remaining 45 percent interest in GreenWing with its portfolio of mature and early development wind projects and changed the name in December 2008 to AltaGas Renewable Energy Limited Partnership. In 2009 AltaGas acquired the 100-MW Glenridge wind development project near Medicine Hat, Alberta. This is a strategic asset that, once operational, will add fuel diversity to AltaGas' power generation portfolio and is expected to generate Alberta based environmental attributes that can be used to offset environmental costs associated with the Sundance B PPA. With these acquisitions, AltaGas has a portfolio of 1,500 MW of wind power, 500 MW in Canada and 1,000 MW in the northern and western United States. The AltaGas wind portfolio is diverse geographically and its assets are located in regions that have strong support for renewable energy mandated through renewable portfolio standards and utility-sponsored PPA auctions. AltaGas believes these assets will generate further growth for the power infrastructure business.

AltaGas has two projects, Reston and Yellowhead, located in Manitoba totalling 400 MW. These projects are mature projects that are eligible for future calls for power with Manitoba Hydro. The Glenridge project in Alberta has completed most of the Environmental Assessment and has received an Interconnection Approval with the AESO. Once constructed, Power from the Glenridge project will be sold into the Alberta merchant market and is expected to be integrated into the existing AltaGas Alberta power portfolio to optimize sales. The 1,000 MW of wind development projects in the United States is comprised of properties at Walker Ridge, Soledad, Ghost Town and Mojave in California, Chateau Hills in New Mexico, Roughrider in North Dakota, Vinegar Peak, Rhyolite and Spanish Flats in Nevada and Burlington in Colorado. AltaGas intends to continue development of these projects by erecting meteorological towers and conducting transmission, wind resource and environmental studies at these sites.

Hydroelectric Generation

In 2008 AltaGas acquired an effective 25 percent interest in Boston Bar Limited Partnership which owns a 7-MW run-of-river hydroelectric facility on Scuzzy Creek, near Boston Bar, British Columbia and which is under a 20-year electricity purchase agreement with BC Hydro until 2015. At the same time, AltaGas acquired two 10-MW run-of-river development projects near Boston Bar, British Columbia: Log Creek and Kookipi Creek. Both the Log Creek and Kookipi Creek projects are supported by 40-year Electricity Purchase Agreements with BC Hydro. During 2010 AltaGas has advanced the environmental studies and engineering design of these projects. Based on the information gathered to date and the ongoing consultation with First Nations, AltaGas is reviewing the development timelines for these projects.

Also in 2008 AltaGas acquired four potential run-of-river hydro projects in British Columbia ranging from 6.5 MW to 24 MW for $4.5 million. The projects remain under review and provide AltaGas with the potential to develop approximately 50 MW of hydroelectric generation in British Columbia.

In March 2010 AltaGas received its amended Environmental Assessment Certificate for the largest of its three northwest British Columbia run-of-river projects, the Forrest Kerr Project, which is a 195 MW run-of-river hydroelectric project. In May 2010 AltaGas entered into a 60-year Electricity Purchase Agreement with BC Hydro for the Forrest Kerr Project, as well as an Impacts and Benefit Agreement with the Tahltan First Nation. In addition, AltaGas entered into an agreement with the British Columbia Transmission Corporation (now BC Hydro) to contribute to the development of the Northwest Transmission Line ("NTL"). Forrest Kerr Project will be the anchor tenant for the proposed NTL, along with the two smaller projects under development by AltaGas in the same vicinity, the McLymont Creek Project and the Volcano Creek Project, which will both feed into the BC Hydro electrical system through Forrest Kerr.

The Forrest Kerr Project is currently under construction, with the camp complete. Civil works commenced in February 2011 and tunnelling activities are expected to begin in late March 2011. Commercial operations at Forrest Kerr are expected to begin in July 2014.

AltaGas is currently going through the BC Environmental Assessment process for the McLymont Creek Project which has a capacity of 50 to 70 MW and is located 10 km west of the Forrest Kerr Project. McLymont Creek will interconnect at the Forrest Kerr switchyard. Engineering feasibility work is underway and detailed design work will start in 2012. The Volcano Creek Project, which has a capacity of 15 to 18 MW, is currently going through environmental studies and is located 10 km east of the Forrest Kerr Project and will also interconnect at the Forrest Kerr Switchyard. Both of these projects are the subject of ongoing negotiations with the Tahltan First Nation as well as discussions with BC Hydro with respect to electricity purchase agreements.

The NW Projects have a combined generating capacity of approximately 277 MW and will contribute to the Province of British Columbia's goal to achieve energy self-sufficiency by 2016. They will also help the Province meet its clean energy needs in an environmentally and socially responsible manner by offsetting the use of electricity generated from fossil fuels.

The main risk faced in the conventional power business is the fluctuation in the margin between power revenue and the cost for power. This is generally created through changes in power prices, increases in operating costs, changes in transmission rates and reductions in power available for sale mainly due to outage and force majeure events. AltaGas mitigates this risk through disciplined power hedging strategies, including direct marketing of electricity to end-use customers and portfolio diversity. AltaGas uses hedges to fix the selling prices on a portion of its available capacity prior to the beginning of any calendar year. Hedge contracts tend to have terms ranging from one to 36 months. AltaGas also satisfies its own electrical demand requirements of approximately 8 MW and supplies approximately 50 MW to Alberta commercial and industrial power customers for terms of up to 8 years.

In the event of any force majeure related to the Sundance B PPAs that results in permanent destruction of the units, ASTC is entitled to a termination payment from the Balancing Pool equal to its portion of the net present value of the amortized Sundance B PPAs' purchase price to that date. AltaGas has further minimized the risk of a force majeure event by diversifying its supply over two independent base load Sundance B units, acquiring gas-fired peaking capacity and constructing cogeneration capacity. In addition, delivery obligations for certain hedges are suspended during outages.

The main risk faced in the renewable hydroelectric power business is variations in the stream flow necessary for power generation in AltaGas' run-of-river power projects once built. AltaGas mitigates this risk through hydrological studies and data to seek to confirm that sufficient water flow is available to generate sufficient electricity for the economic viability of its projects. Annual and seasonal deviations from the long-term average can be significant.

The main risk faced in the renewable wind power business AltaGas' is variations in wind which could affect the amount of power generated. AltaGas mitigates this risk through wind studies and data to seek to confirm that sufficient wind flows are available to generate sufficient electricity for the economic viability of its projects. Annual and seasonal deviations from the long-term average can be significant.

A part of AltaGas' business portfolio risk mitigation strategy is geographic and fuel type diversification. The Bear Mountain Wind Park in British Columbia has a capacity of 102 MW. In addition, AltaGas is also pursuing development of wind power and run-of-river hydroelectric projects in western Canada and the United States.

Competition

All of the power produced in Alberta is currently sold into the Pool, which operates an open market for the exchange of electricity and is run by the AESO. The AESO establishes the power price based on offers from Pool participants using a uniform pricing model whereby the marginal unit establishes the price for all generators. AESO system controllers sort the offers by price into a merit order beginning with the lowest priced offer, thereby defining a supply curve for each

hour. By matching energy supply with demand, the Pool establishes a uniform hourly market price, which is published on the AESO's website.

In Alberta, coal-fired electrical generation, which is generally produced at a lower cost than gas-fired electrical generation, is a base load source of supply, while gas-fired units tend to set the marginal price. Management is not aware of any significant increases in power generation capacity in Alberta in the next several years that would alter the tendency for natural gas-fired electricity to continue to influence the marginal price in Alberta.

The Sundance plant is one of the lowest-cost power producers in Alberta and therefore among the lowest in the dispatch merit order. AltaGas does not expect this situation to change with the addition of new capacity on the grid. Power prices have been under pressure since early 2009 due to a combination of reduced demand growth, low gas prices and the addition of new generation capacity to the grid. However, more recently there has been a strengthening in both spot and forward prices in Alberta and AltaGas remains confident in the ongoing profitability of its power generation assets.

Power generated from the Bear Mountain Wind Park is not currently exposed to power price volatility as the power generated is sold to BC Hydro at a fixed price with 50 percent escalated by the Canadian Consumer Price Index for 25 years.

UTILITY DIVISION

AltaGas acquired this business in October 2009. AltaGas' Utility Division contributed net revenue of $71.9 million for the year ended December 31, 2010, representing approximately 15 percent of AltaGas' total net revenue before intersegment eliminations.

Regulated Businesses

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

Regulatory Process

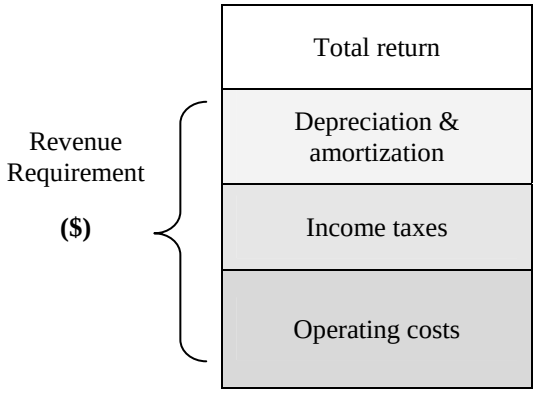
The distribution of natural gas in Alberta, Nova Scotia and the Northwest Territories is regulated by the AUC, the NSUARB and the NWTPUB respectively. The AUC's and the NSUARB's jurisdiction includes the approval of a distribution tariff for regulated distribution utilities which includes the rates charged and the terms and conditions on which service is to be provided by those utilities. For Inuvik Gas, rates are set by the utility to be market competitive. Inuvik Gas is regulated on a complaint basis and is required to file annual financial statements and quarterly comparisons to local alternative fuels with the NWTPUB.

The following description of the regulatory process applies to AUI and Heritage Gas. The AUC and the NSUARB approve distribution rates based on a cost-of-service regulatory model. Under this model, the AUC and the NSUARB seek to provide the distribution utility with an opportunity to recover all prudently incurred operating, depreciation, income tax, and financing costs, and to earn a reasonable return on equity. The AUC and the NSUARB attempt to ensure that tariffs are just and reasonable, provide incentives for investments, and are not unduly preferential, arbitrary, or unjustly discriminatory. The natural gas delivered to the end consumer may be purchased from a retail gas supplier at contract prices or from the utility as the default supplier, at a regulated rate based on the current cost of gas to the utility.

The regulatory process usually proceeds through two phases. In the first phase (Phase 1) the distribution utility's total revenue requirement is determined. In the second phase (Phase 2) specific rates to be charged to different classes of consumers and the terms and conditions of service are determined. Phase 1 and Phase 2 may be applied for in a single application or in separate applications at different times. In general, a full Phase 1 and Phase 2 process may take over a year from original application to final decision by the AUC, or up to six months by the NSUARB.

Phase 1

The principal components comprising an approved Phase 1 revenue requirement are as follows (the diagram does not necessarily represent the relative size of such principal components comprising an approved revenue requirement):

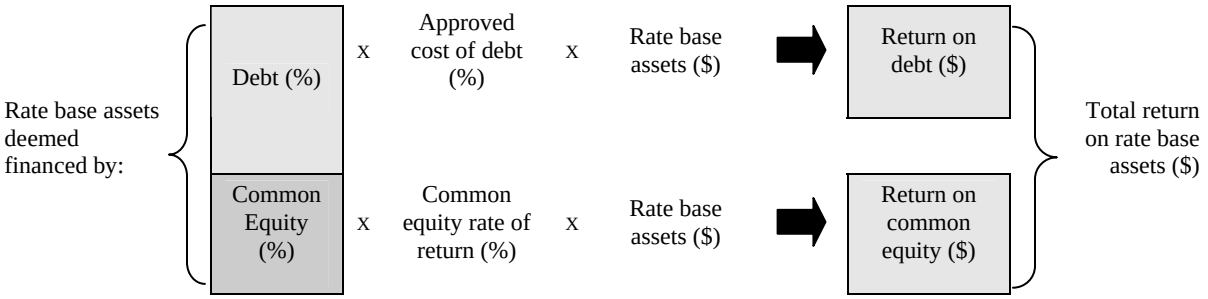


Rate Base

Rate base is the approved investment in plant, property and equipment, less accumulated depreciation, plus allowance for working capital. Net rate base excludes from the rate base no-cost capital, which consists of unamortized customer-contributions and grants from governments and customers. Working capital generally includes an allowance for delays in receipt of cash and average balance for other deferred or prepaid expenses. The rate base at Heritage Gas includes Heritage Gas' revenue deficiency accrual.

Total Return

Total return is the return on the capital invested by the distribution utility in its approved rate base, financed through a deemed capital structure comprised of debt and equity, calculated, as a matter of general practice, on the following basis (the diagram does not necessarily represent all the components, or the relative size of such components, within an approved revenue requirement total return on rate base assets).



Depreciation and Amortization

Depreciation and amortization is an allowance for a return of capital and is the depreciation on the rate base assets that is determined based on depreciation studies filed by a distribution utility, and approved by the AUC or NSUARB. It is net of any customer contribution amortization.

Income Taxes

Income taxes are the allowance for the recovery of income taxes paid in respect of the regulated operations of the distribution utility.

Operating Costs

Operating costs are the operating costs associated with operating a distribution utility that are determined to be prudent by the regulator.

Other revenue generated by the utility through its regulated operations reduces the total regulated revenue requirement collected through rates, from end-users or customers.

The following table summarizes the actual gross and net mid-year rate base for AUI and Heritage Gas for the years 2010 and 2009:

($ millions)	2010	2009
AUI		
Gross rate base	190.0	177.7
Less: CIAC	54.5	54.7
Net rate base	135.5	123.0
Heritage Gas [(1)]		
Gross rate base	177.0	139.4
Less: CIAC	2.0	2.0
Less: Province of Nova Scotia Loan	5.6	5.6
Net rate base	169.4	131.8

Note:

(1) All figures shown in this section are for an ownership interest in Heritage Gas of 100 percent. Prior to November 18, 2009, Utility Group owned a 24.9 percent interest in Heritage Gas.

The following table summarizes AUI's and Heritage Gas' approved allowed rate of return on equity and cost of debt:

Operating year	Capital Structure Debt/Equity (%)	Allowed Rate of Return on Equity (%)	Cost of Debt (%)
AUI			
2010	57/43	9.00	6.80[(1)]
Heritage Gas			
2007-2011	55/45	13.0	8.75

Note:

(1) The allowed cost of debt presented is as applied for in AUI's 2010-2012 GRA. A decision on the GRA is expected in late 2011.

Phase 2

An approved Phase 2 rate structure results in rate schedules applicable to different customer classes as well as terms and conditions governing the services provided to customers. The determination of rate structure is complex, typically involving the allocation of the Phase 1 revenue requirement to customer classes using the principle of cost causation. Rates are based on a set of rate design principles, with the primary principle being to collect revenue from a customer class equal to the costs to serve the class.

Delivery charge billing determinants are either fixed or vary with the volume of gas delivered. The fixed billing determinants do not vary with energy deliveries and as such provide some revenue stability and moderate the impact on revenue of fluctuations in gas volumes delivered.

AUI

AUI has operated as a provincially regulated natural gas distribution utility in Alberta since 1954. Its head office is located in Leduc, Alberta. AUI delivers natural gas to residential, farm, commercial and industrial consumers in more than 90 communities throughout Alberta. AUI also owns transmission facilities, including high-pressure pipelines that deliver natural gas from gas sources to the distribution systems. AUI's primary objective and responsibility is to recover its costs and earn a return of, and return on, capital while maintaining high operating standards to ensure safe, dependable, cost-effective and secure natural gas supply and delivery for its customers.

AUI operates in a mature market and has achieved nearly 100 percent saturation within its franchise areas, with the exception of those few consumers choosing alternate fuel sources or those living in more remote areas where natural gas service has been cost-prohibitive. The Alberta natural gas distribution market is dominated by a major distributor that serves approximately 85 percent of natural gas consumers. AUI serves approximately 6 percent of Alberta customers, with the remainder of the market served by member-owned natural gas cooperatives and municipally owned systems.

Within its existing franchise areas AUI averaged annual growth of 2.0 percent in the years 2000 through 2005, 3.5 percent in the years 2006 and 2007, and 3.0 percent in 2008. In 2009, the rate of growth in the number of customers returned to a level of 1.8 percent as a result of the general slowdown in the Alberta new housing market in that year. The rate of growth in 2010 was 2.3 percent. AUI expects annual growth in new service sites of approximately 2.0 percent for 2011 and thereafter.

AUI aggressively pursues opportunities to develop service areas that are not currently served with natural gas. In recent years, these expansion opportunities have typically come with the extension of gas service to small aboriginal communities in northern Alberta. Expansion opportunities that currently exist represent relatively minor asset growth, but AUI remains committed to its strategy of pursuing expansion projects that meet management's target return on investment.

AUI's cash expenditures for capital for the years ended December 31, 2010 and 2009 are shown in the following table:

($ millions)	**2010**	**2009**
New business	8.0	8.0
System betterment and gas supply	7.2	5.1
General plant	11.5	8.4
	26.8	21.5
Less: CIAC	2.1	2.3
Total	24.7	19.3

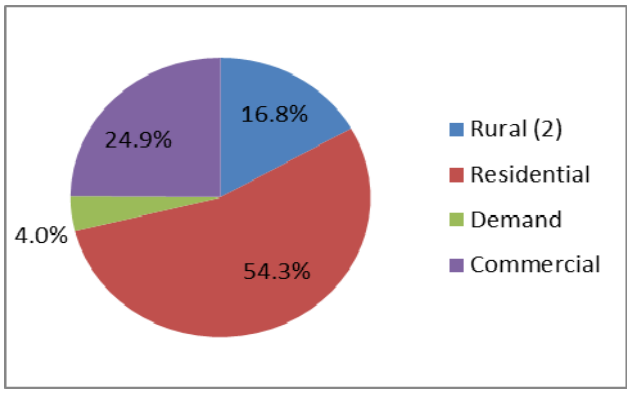
Operations

AUI's distribution system consists of 20,060 km of pipeline, operating at pressures ranging from 200 kilopascals to 8,755 kilopascals. AUI uses steel, aluminum and composite pipe to transport natural gas at pressures greater than 690 kilopascals, while natural gas at lower pressures is transported primarily by steel and plastic pipe. There are 738 small and mid-sized metering and pressure regulating stations throughout AUI's distribution network. AUI operates its gas distribution systems through a network of 16 district offices.

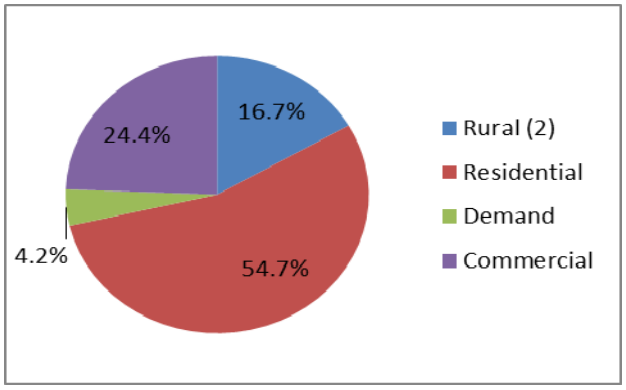
In 2010, the total throughput of natural gas transported for three producers and delivered to 70,788 end consumer service sites had a total energy value of approximately 21.5 PJ.

AUI's market consists primarily of residential and small commercial consumers located in smaller population centres or rural areas of Alberta. New service sites added totalled 1,592 in 2010 and 1,241 in 2009. Of the 21.5 PJ of natural gas AUI delivered through AUI's system in 2010, 12.4 PJ was attributed to 69,781 non-demand service sites that received default gas supply under the regulated rate, 1.5 PJ to 990 non-demand service sites that received gas supply from natural gas retailers, 2.3 PJ to 49 demand-based service sites and 5.3 PJ for three producer transporters. Producer transportation revenues are primarily derived from capacity charges and do not vary significantly with changes in energy transported. While producer transportation throughput comprises a significant percentage of total throughput, this service produces significantly less revenue than that derived from distribution services.

AUI Revenue by Service Type for 2009 (1)



AUI Revenue by Service Type for 2010 (1)



Notes:
(1) Excludes revenue from producer transportation service.
(2) Rural customers are located outside of incorporated areas and consist primarily of farms, irrigation pumps, grain dryers and greenhouses.

AUI provides service to designated areas in Alberta under the authority granted by franchise agreements or other agreements granted as permits or approvals issued pursuant to applicable statutes. As of December 31, 2010, AUI held a total of 78 such franchises and agreements: 49 municipal distribution franchises granted pursuant to the *Municipal Government Act* (Alberta), nine permits granted on four First Nations by Indian and Northern Affairs Canada under the authority of the *Indian Act* (Canada) and 20 rural franchise approvals issued under the authority of the *Gas Distribution Act* (Alberta). Four of the rural franchises cover Métis settlements, each of which has a separate operating agreement.

Franchises/Permits	# of Agreements	% of Total Service Sites	Average Remaining Term
Municipal Government Act Franchises	49	64.3	4.4 years
Indian and Northern Affairs Canada Permits	9	1.5	Varying
Gas Distribution Act Franchises	16	33.1	Perpetual
Métis Settlement Operating Agreements	4	1.1	2.0 years

The three largest municipalities served by AUI (City of Leduc, Town of Beaumont and Town of Drumheller) accounted for approximately 20 percent of AUI's total net revenue and 19 percent of energy delivered in 2010.

Seasonality

The natural gas distribution business in Alberta is highly seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. Natural gas delivered during the winter season typically accounts for approximately two-thirds of annual natural gas deliveries, resulting in profitable first and fourth quarters and net losses in the second and third quarter. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

Delivery rates for AUI are set based on the 20-year rolling average heating Degree Days expected for the application period. Variations from expected deliveries are for the account of the shareholders.

	2010				2009			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	1,851	252	568	1,956	1,950	140	644	2,403
Degree Days - normal	1,773	205	552	2,180	1,767	206	542	2,172

Heritage Gas

Heritage Gas is a greenfield natural gas distribution utility in Nova Scotia. Heritage Gas' franchise was granted on February 7, 2003 and gives it the exclusive right to distribute natural gas to all or part of six counties in Nova Scotia, including the Halifax Regional Municipality until December 31, 2028. Heritage Gas' head office is located in Dartmouth, N.S.

As a greenfield operation, Heritage Gas has a relatively small proportion of the Nova Scotia energy end-use market. The dominant energy source for space heating is oil, with over 50 percent of the market share. Most major industrial and institutional consumers use Bunker C heavy fuel oil, while smaller commercial and residential consumers use No. 2 fuel oil. Electricity, primarily used by residential consumers, has the second largest market share, with over 25 percent of the market share. This is followed by propane and wood fuel, which are mainly used by smaller residential customers. Natural gas is fifth in market share. Natural gas has a competitive price advantage compared to all alternative energy sources.

Natural gas is more efficient and provides environmental advantages when compared to the other forms of fuel in the market and there are some government incentives in place to reduce the cost of conversion to natural gas for residential and commercial customers. As a result, AltaGas believes that Heritage Gas will continue to expand its customer service base within the Nova Scotia market.

Potential customers are those with access to natural gas service, thereby having the opportunity to switch heating fuel sources, mainly from oil or electricity, to natural gas. At the end of 2010 there were approximately 9,435 potential customers of whom 3,796 were commercial energy consumers and approximately 5,639 were residential energy consumers with access to the Heritage Gas distribution system in the Halifax Regional Municipality and in the Town of Amherst and Cumberland County. Of the 9,435 potential customers, Heritage Gas had installed service lines to 3,246 customers over its years of operations, of which 2,937 were activated by December 31, 2010.

In 2010, Heritage Gas connected 502 new customers, compared to 550 in 2009. Heritage Gas expects a growth in activations in 2011 as a result of the higher cost of heating oil compared to natural gas and customer awareness of the environmental benefits of natural gas. In 2011, Heritage Gas expects to attach and activate approximately 750 new customers and expects to increase annual natural gas deliveries to 4.8 PJ.

Capital expenditures by Heritage Gas for the years ended December 31, 2010 and 2009 are shown in the following table:

Capital Expenditures

($ millions)	**2010**	**2009**
New business	30.9	15.1
General plant	0.1	0.2
Total	31.0	15.3

In 2010 Heritage Gas invested $30.9 million to continue expanding in two of its franchise markets. The major focus in 2010 was the entrance into the Halifax mainland (in the areas of Bedford, Fairview, and Clayton Park) market adding 30 km of new pipelines to the Heritage Gas natural gas distribution system and continuing development of the Halifax peninsula.

Heritage Gas' capital expenditures for 2011 are expected to be approximately $20.2 million. Heritage Gas expects the higher cost of heating oil compared to natural gas and customer awareness of the environmental benefits of natural gas will continue to drive customer conversions to natural gas.

Operations

On December 31, 2010, Heritage Gas' distribution system consisted of approximately 289 km of pipeline infrastructure, approximately 230 km in the Halifax Regional Municipality and approximately 59 km in Amherst.

At the end of 2010 Heritage Gas had installed service lines to 3,246 customers, of which 2,937 were activated by year-end. In addition, Heritage Gas had signed commitments for service from an additional 356 customers in the Halifax Regional Municipality and Amherst with expected connection dates in 2011. Heritage Gas is contemplating numerous future development projects throughout its franchise area and expects to pursue these and other future growth opportunities that are contiguous to its current operations. In 2010 the total peak-day capacity of the Heritage Gas system was 124,000 GJ per day, excluding the Burnside facility.

Heritage Gas purchases gas sourced from offshore Nova Scotia under a negotiated contract with a wholesale gas marketer. The current contract expires on October 31, 2011. The cost of gas purchased is flowed through to the distribution customers and does not impact net income. The natural gas received into the Heritage Gas system is delivered from Maritimes & Northeast Pipeline laterals.

In awarding the franchise to Heritage Gas in 2003, the NSUARB found that there is adequate gas supply to meet both the immediate and long-term needs of Nova Scotia natural gas customers. However, the offshore Nova Scotia gas supply area has not been developed to the extent that was initially envisioned and the level of current reserves estimates has been reduced and there is speculation that current production levels will sustain natural gas demand for a shorter period than previously expected. Heritage Gas has access to gas supply from the western part of the North American pipeline system, which management believes will ensure that Heritage Gas has sufficient gas supplies to serve all its customers as it grows.

Inuvik Gas

Inuvik Gas is a corporation equally owned by AltaGas, the Inuvialuit Petroleum Corporation, and ATCO Midstream NWT Ltd.

On December 1, 1997 Inuvik Gas signed an exclusive franchise agreement with the Town of Inuvik to distribute and sell natural gas within the town. The 15-year initial term of the franchise began with the commencement of deliveries in August 1999 and can be renewed by mutual agreement for a further 10-year period. The Ikhil Gas Project comprises three components, the producing wells, the gas producing facilities and the natural gas distribution system, each governed separately. Inuvik Gas owns the natural gas distribution system and provides residents and businesses in the Town of Inuvik with a secure supply of natural gas for power and heating.

Inuvik Gas is regulated by the NWTPUB and is presently exempt from full regulation as a public utility. The NWTPUB is satisfied that competition for alternative fuels in Inuvik is sufficient to negate the need for full regulation. Inuvik Gas reviews the rates charged to customers regularly, and since its rates are market-based, as opposed to the more traditional

cost-of-service, Inuvik Gas has the opportunity to earn a higher return in times of high alternative fuel prices and, conversely, may not recover its cost of operations in periods of low alternative fuel prices.

The Inuvik Gas distribution system, consisting of 47 km of pipe within the Town of Inuvik, was the first of its type to be buried in permafrost conditions. The total number of customers using natural gas service was 932 at December 31, 2010, up from 905 at December 31, 2009.

Inuvik Gas purchases gas for resale from the Ikhil Joint Venture under a gas purchase agreement through to 2014, at a price adjusted annually on August 1 based on the change in the average price of high sulphur diesel at Edmonton. This arrangement is the sole source of Inuvik Gas' gas supply. Should the Mackenzie Gas Project proceed, Inuvik Gas would expect to have access to natural gas supply from that project during and beyond the life expectancy of the two wells currently servicing the Town of Inuvik.

Ikhil Joint Venture

The Ikhil Joint Venture owns and operates two gas wells, a processing facility and a pipeline that delivers natural gas to Inuvik Gas and NWTPC. The joint venture partners and their respective ownership interests are as follows: AltaGas (33.3335 percent), Inuvialuit Petroleum Corporation (33.3335 percent) and ATCO Midstream NWT Ltd. (33.333 percent).

The Ikhil Joint Venture gas reserves are the sole gas supply for the Inuvik Gas distribution business and for the gas-fired generation of NWTPC in Inuvik. The wells produce an average of approximately 1.8 Mmcf/d (0.6 Mmcf/d net to AltaGas) of sweet dry gas into a field processing facility that cools the gas and delivers it to the town of Inuvik. The Ikhil reservoir had remaining recoverable gas of approximately 9 Bcf (3 Bcf net to AltaGas) as at December 31, 2010. Pipeline infrastructure is currently not in place to utilize other natural gas reserves discovered in the area. The supply contract to Inuvik Gas and NWTPC ends in 2014, approximately 14 years prior to the end of the expected life of the natural gas reserves. The sales price is adjusted annually on August 1 based on the change in Edmonton average wholesale diesel price.

CORPORATE SEGMENT

AltaGas makes investments where it considers it to be prudent to do so and where it sees an opportunity to create value. The resulting investments and related revenues and expenses not directly identifiable with the operating divisions are reported in the Corporate reporting segment. The Corporate segment contributed net revenue of **$**1.6 million for the year ended December 31, 2010, representing less than 1 percent of AltaGas' total net revenue before intersegment eliminations.

AltaGas holds shares of Magma Energy Corporation, which were initially acquired on January 14, 2009. Magma Energy Corporation began trading on the TSX on July 7, 2009 at which time AltaGas increased its ownership. In July 2010 AltaGas acquired additional shares of Magma. AltaGas held approximately five percent of the common shares of Magma Energy Corporation on December 31, 2010.

ALTAGAS LTD.

AltaGas is the resultant corporation from the amalgamation of AltaGas Ltd., AltaGas Conversion Inc. and AltaGas Conversion #2 Inc. pursuant to the Corporate Arrangement. As a result, AltaGas owns, directly or indirectly, all of the assets that the Trust owned, directly or indirectly, prior to the corporate conversion of the Trust.

EMPLOYEES

At December 31, 2010 there were 810 individuals employed in AltaGas' businesses.

Gas	363
Power	43
Utility	286
Corporate	118
	810

DIRECTORS AND OFFICERS

As at February 23, 2011 the directors and executive officers of AltaGas Ltd., as a group, owned beneficially, directly or indirectly, or exercised control or direction over 3,256,021 of the outstanding shares, or approximately 3.9 percent of the

outstanding shares. As at February 23, 2011 certain of the directors and officers also had been granted Trust options to acquire an aggregate of 1,873,500 shares.

DIRECTORS

The number of directors of AltaGas is to be determined from time to time by resolution of the Board of Directors. The number of directors currently comprises nine, of which eight are independent directors.

The term of office of any director continues until the annual meeting of shareholders of AltaGas next following the director's election or appointment or (if an election or appointment of a director is not held at such meeting or if such meeting does not occur) until the date on which the director's successor is elected or appointed, or earlier if the director dies or resigns or is removed or disqualified, or until the director's term of office is terminated for any other reason in accordance with the constating documents of AltaGas. The shareholders are annually entitled to elect the Board of Directors.

The following table sets forth the names of the Directors of AltaGas Ltd. on February 23, 2011, their municipalities of residence and their principal occupations within the last five years.

Name of Director, Municipality of Residence and Position	Principal Occupation During the Past Five Years	Director Since
David W. Cornhill [4] Calgary, Alberta, Canada Chairman and Chief Executive Officer	Mr. Cornhill is a founding member of AltaGas Services Inc., predecessor to AltaGas. He has served as Chairman and Chief Executive Officer since AltaGas Services Inc.'s inception on April 1, 1994 and was appointed as a Director of the General Partner on May 1, 2004. Prior to forming AltaGas Services Inc., Mr. Cornhill served in the capacities of Vice President Finance and Administration, and Treasurer of Alberta and Southern Co. Ltd. from 1991 to 1993 and as President and Chief Executive Officer until March 31, 1994.	July 1, 2010 Director of the General Partner from May 1, 2004 to June 30, 2010 Director of AltaGas Services from March 28, 1994 to April 30, 2004
Allan L. Edgeworth [1] Calgary, Alberta, Canada Director	Mr. Edgeworth has been the President of ALE Energy Inc., a private consulting company, since January 2005 and is a Commission Member of the Alberta Securities Commission. Mr. Edgeworth was the President and Chief Executive Officer of Alliance Pipeline Ltd. from 2001 until December 2004. Mr. Edgeworth joined Alliance Pipeline Ltd. in 1998 as Executive Vice President and Chief Operating Officer.	July 1, 2010 Director of the General Partner from March 2, 2005 to June 30, 2010
Hugh A. Fergusson[1] Calgary, Alberta, Canada Director	Mr. Fergusson is an independent businessman. Mr. Fergusson is currently President of Argyle Resources Inc., a private petrochemical and energy consulting organization. He retired in 2004 as Vice President Hydrocarbons and Energy after over 25 years of service with The Dow Chemical Company, an international chemicals company listed on numerous stock exchanges.	July 1, 2010 Director of the General Partner from May 7, 2008 to June 30, 2010
Denis C. Fonteyne[1] Calgary, Alberta, Canada Director	Mr. Fonteyne is the President of Dendon Resources Ltd., a private consulting company, has been a natural gas industry consultant since 1997 and brings over 40 years of industry experience to the board of directors. Mr. Fonteyne has held a number of senior executive positions in the oil and gas industry, including eight years with CanStates Gas Marketing Ltd. prior to his retirement as Executive Vice-President in 1996.	July 1, 2010 Director of the General Partner from May 1, 2004 to June 30, 2010 Director of AltaGas Services from September 1, 1998 to April 30, 2004
Daryl H. Gilbert [1][3] Calgary, Alberta, Canada Director	Mr. Gilbert joined JOG Capital Inc. in May 2008 as a Managing Director and Investment Committee Member. Prior thereto, Mr. Gilbert was an Independent businessman since January 2005. Prior to that, Mr. Gilbert was President and Chief Executive Officer of Gilbert Laustsen Jung Associates Ltd., an engineering consulting firm.	July 1, 2010 Director of the General Partner from May 1, 2004 to June 30, 2010 Director of AltaGas Services from May 4, 2000 to April 30, 2004
Robert B. Hodgins [1] Calgary, Alberta, Canada Director	Mr. Hodgins has been an Independent businessman since November 2004. Prior to that, Mr. Hodgins served as the Chief Financial Officer of Pengrowth Corporation from 2002 to 2004. Prior to that, Mr. Hodgins held the position of Vice President and Treasurer of Canadian Pacific Limited 1998 to 2002 and was Chief Financial Officer of TransCanada Pipelines Limited from 1993 to 1998.	July 1, 2010 Director of the General Partner from March 2, 2005 to June 30, 2010

Name of Director, Municipality of Residence and Position	Principal Occupation During the Past Five Years	Director Since
Myron F. Kanik [(1)(2)] Calgary, Alberta, Canada Director	Mr. Kanik has been the President of Kanik and Associates Ltd., an energy industry consulting company, since 1999. Mr. Kanik was President of the Canadian Energy Pipeline Association from 1993 to 1999, and prior thereto was with the Alberta Department of Energy where he served in various capacities, including Deputy Minister.	July 1, 2010 Director of the General Partner from May 1, 2004 to June 30, 2010 Director of AltaGas Services from June 1, 2001 to April 30, 2004
David F. Mackie [(1)] Houston, Texas, United States Director	Mr. Mackie is a U.S.-based natural gas industry consultant and venture capital investor. Mr. Mackie brings a broad range of experience to the board of directors, having spent more than 32 years in various executive capacities, primarily with El Paso Natural Gas Co. and Transco Energy Co. Mr. Mackie also has extensive consulting experience with many senior energy companies, including the Maritimes and Northeast Pipeline Project.	July 1, 2010 Director of the General Partner from May 1, 2004 to June 30, 2010 Director of AltaGas Services from January 12, 1995 to April 30, 2004
M. Neil McCrank, Q.C., P.Eng. [(1)] Calgary, Alberta, Canada Director	Mr. McCrank is Counsel to the Calgary office of Borden Ladner Gervais LLP. Mr. McCrank was Chairman of the Alberta Energy and Utilities Board from July 1998 until his retirement on March 31, 2007. Prior thereto, Mr. McCrank was with the Alberta Department of Justice, serving in various capacities, including Deputy Minister of Justice from 1989 to 1998. He currently serves as Chairman of the Canadian Energy Research Institute of Canada and Chairman of the Canadian Association of the World Petroleum Council, and is a consultant to all provincial and territorial governments in Canada with respect to justice issues.	July 1, 2010 Director of the General Partner from December 10, 2007 to June 30, 2010

Notes:
(1) Independent director.
(2) Lead director.
(3) Mr. Daryl H. Gilbert, a director of AltaGas, was a director of Globel Direct, Inc. ("Globel") from December, 1998 to June 2009. Globel was the subject of cease trade orders issued by the Alberta Securities Commission ("ASC") on November 22, 2002 and the British Columbia Securities Commission ("BCSC") on November 20, 2002 for failure to file certain financial statements. Globel filed such financial statements and the cease trade orders were removed on December 20, 2002 and December 23, 2002, respectively. On June 12, 2007, Globel was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the *Companies' Creditors Arrangement Act*, which protection expired on December 7, 2007, following which the monitor was discharged on December 12, 2007 and a receiver/manager was appointed. Subject to the completion of matters relating to the wind-up of the administration of the receivership, the receiver was discharged on September 3, 2008. Globel has ceased operations, and as a result became the subject of cease trade orders issued by the ASC on September 24, 2008 and the BCSC on September 30, 2008 for failure to file certain disclosure documents. Globel was struck from the Alberta corporate registry on June 2, 2009.
(4) Mr. Cornhill is not considered to be an independent director as he is an executive officer of the General Partner.

AltaGas has four committees of the Board of Directors: (1) Audit, (2) Governance, (3) Human Resources and Compensation (HRC) Committee and (4) Environment, Occupational Health and Safety (EOH&S) Committee. The members of each of these committees, as of December 31, 2010, are identified below:

Director	Audit Committee	Governance Committee	HRC Committee	EOH&S Committee
David W. Cornhill				✓
Allan L. Edgeworth	✓			Chair
Hugh A. Fergusson	✓		✓	
Denis C. Fonteyne			✓	✓
Daryl H. Gilbert	✓		Chair	
Robert B. Hodgins	Chair	✓		
Myron F. Kanik		Chair	✓	
David F. Mackie		✓	✓	
M. Neil McCrank		✓		✓

EXECUTIVE OFFICERS

The names, municipality of residence and position of each of the current executive officers of AltaGas Ltd. are as follows:

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
David W. Cornhill Calgary, Alberta, Canada Chairman and Chief Executive Officer	Chairman and Chief Executive Officer of AltaGas since July 1, 2010 Chairman and Chief Executive Officer of the General Partner from 2004 to June 30, 2010 and of ASI from 1994 to 2004.
Richard M. Alexander Calgary, Alberta, Canada President	President of AltaGas since January 2011. President and Chief Operating Officer of AltaGas Ltd. from July 1, 2010 to December 2010. President and Chief Operating Officer of the General Partner from January 2008 to June 30, 2010. Executive Vice President Chief Operating Officer and Chief Financial Officer of the General Partner from January 2007 to January 2008. Senior Vice President Finance and Chief Financial Officer of the General Partner from May 2006 to January 2007. Vice President Finance and Chief Financial Officer Niko Resources Ltd. October 2003 to April 2006. Vice President Investor Relations and Communications of Husky Energy Inc. from July 2001 to September 2003. Treasurer Husky Energy Inc. August 2000 to July 2001.
Gregory A. Aarssen Chatham, Ontario, Canada Co-President Gas	Co-President Gas of AltaGas since January 2011. Vice President Corporate Affairs of AltaGas from July 1, 2010 to December 2010. Vice President Corporate Affairs of AltaGas from January 2008 to June 30, 2010. Divisional Vice President Energy Management of AltaGas from January 2007 to January 2008. Vice President Retail Services PremStar October 2004 to January 2007. Vice President PremStar Energy Canada Ltd. January 1998 to October 2004.
Patricia M. Newson Calgary, Alberta, Canada President AltaGas Utility Group Inc.	President AltaGas Utility Group Inc. from January 2010. President and CEO AltaGas Utility Group Inc. from July 2005 to January 2010. Senior Vice President of the General Partner from May 2006 to December 2008. Senior Vice President Finance and CFO of the General Partner from 2004 to April 2006. Senior Vice President Finance and CFO of ASI from 1996 to 2004.
Deborah S. Stein Calgary, Alberta, Canada Vice President Finance and Chief Financial Officer	Vice President Finance and Chief Financial Officer of AltaGas from July 1, 2010. Vice President Finance and Chief Financial Officer of the General Partner from January 2008 to June 30, 2010. Vice President Finance from January 2007 to January 2008. Vice President Controller from October 2005 to January 2007. Vice President Corporate Risk from January to October 2005. Manager Investor Relations TransCanada Corporation from 2001 to 2005.
Randy W. Toone Calgary, Alberta, Canada Co-President Gas	Co-President Gas of AltaGas since December 2010. Divisional Vice President Field Gathering and Processing and Energy Services of AltaGas from July 1, 2010 to December 2010. Divisional Vice President Field Gathering and Processing and Energy Services of AltaGas from October 2009 to June 30, 2010. Divisional Vice President Field Gathering and Processing of AltaGas from February 2009 to October 2009. Divisional Vice President Extraction and Transmission of AltaGas from January 2007 to February 2009. Operations Manager Extraction and Transmission of AltaGas from November 2004 to January 2007. Senior Operations Engineer of AltaGas from November 2003 to November 2004. Plant Engineer Williams Energy Canada January 2002 to November 2003.

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
David R. Wright Calgary, Alberta, Canada Executive Vice President Strategy and Corporate Development and Director	Executive Vice President Strategy and Corporate Development of the AltaGas from July 1, 2010. Executive Vice President Strategy and Corporate Development of the General Partner from January 2008 to June 30, 2010. Executive Vice President of the General Partner from January 2007 to January 2008. Executive consultant from 2005 to January 2007. Executive Vice President General Counsel and Corporate Secretary of EPCOR Utilities Inc. from 2001 to 2005. Prior thereto Partner with Borden Ladner Gervais LLP and Howard Mackie.

Audit Committee Mandate

See attached Schedule A for the Audit Committee Mandate.

Composition of the Audit Committee

The Committee is currently comprised of Allan L. Edgeworth, Daryl H. Gilbert, Hugh A. Fergusson and Robert B. Hodgins. Robert B. Hodgins is the chair of the Committee. All of the members of the Committee are independent and financially literate as defined under Canadian securities law.

Relevant Education and Experience

Allan L. Edgeworth has been the President of ALE Energy Inc. since January 2005. Mr. Edgeworth was the President and Chief Executive Officer of Alliance Pipeline from 2001 until December 2004. Mr. Edgeworth joined Alliance Pipeline in 1998 as Executive Vice President and Chief Operating Officer. Prior to that, Mr. Edgeworth spent almost 20 years with Westcoast Energy where he held various positions including Vice President of Pipeline Operations and Senior Vice President of Regulatory Affairs.

Hugh A. Fergusson has been President of Argyle Resources Inc., a private energy consulting organization, since 2004. Mr. Fergusson was employed for over 25 years with Dow Chemical Company, an international chemicals company. Prior to his retirement from Dow Chemical Company in 2004, Mr. Fergusson was Vice President, Hydrocarbons and Energy.

Daryl H. Gilbert has been an independent businessman since January 2005. Prior to 2005, Mr. Gilbert had a 26-year career with Gilbert Laustsen Jung Associates Ltd., a reservoir engineering company, most recently as President and Chief Executive Officer for 11 years.

Robert B. Hodgins has been an independent businessman since November 2004. Prior to that, Mr. Hodgins was Chief Financial Officer at Pengrowth Energy Trust from 2002 to 2004. Mr. Hodgins was Vice President and Treasurer at Canadian Pacific Limited from 1998 to 2002 and Chief Financial Officer of TransCanada PipeLines Limited from 1993 to 1998. Mr. Hodgins has an Honours Degree in Business from the Richard Ivey School of Business at the University of Western Ontario and is a Chartered Accountant in Ontario and Alberta.

Pre-Approval Policies and Procedures

As set forth in the Committee's charter, the Committee must pre-approve all non-audit services provided by the external auditor and has direct responsibility for overseeing the work of the external auditor.

External Auditor Service Fees by Category

The fees billed by Ernst & Young LLP (E&Y), AltaGas' external auditors, for 2009 and 2010 were as follows:

Category of External Auditor Service Fee	2010	2009
Audit Fees	$767,587	$1,075,936
Audit-Related Fees[(1)]	$14,420	$0.0
Tax Fees[(2)]	$0.0	$11,708
All Other Fees[(3)]	$346,170	$287,670
TOTAL	$1,128,177	$1,375,313

Notes:

(1) Represent the aggregate fees billed by E&Y for assurance and related services that were reasonably related to the performance of the audit or review of AltaGas' financial statements and were not reported under "Audit Fees". The nature of the services was for accounting advice.

(2) Represent the aggregate fees billed by E&Y for professional services for tax compliance, tax advice and tax planning. The nature of the services was tax services and tax planning.

(3) Represent the aggregate fees billed by E&Y for products and services, other than those reported with respect to the other categories of service fees. The nature of the services was for translation services and non-audit/tax related fees.

RISK FACTORS

RISKS RELATING TO THE CORPORATION

A security holder should consider carefully the risk factors set out below. In addition, prospective security holders should carefully review and consider all other information contained in this Annual Information Form before making an investment decision and consult their own experts where necessary. These risks are applicable to AltaGas' current operations and AltaGas' expected future operations.

Capital Markets

AltaGas may have restricted access to capital and increased borrowing costs. As AltaGas' future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, AltaGas' ability to do so is dependent on, among other factors, the overall state of capital markets and investor demand for investments in the energy industry and AltaGas' securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, AltaGas' ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition, results of operations and dividends may be materially and adversely affected as a result.

Based on current funds available and expected cash from operations, AltaGas believes it has sufficient funds available to fund its projected capital expenditures. However, if cash flow from operations is lower than expected or capital costs for these projects exceed current estimates, or if AltaGas incurs major unanticipated expenses related to development or maintenance of its existing assets, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for AltaGas' capital expenditure plans may result in a delay in AltaGas' capital program or a decrease in dividends.

Potential Sales of Additional Shares

AltaGas may issue additional shares in the future to directly or indirectly fund capital expenditure requirements of entities now or hereafter owned directly or indirectly by AltaGas, including financing acquisitions by those entities. Such additional shares may be issued without the approval of shareholders. Shareholders will have no pre-emptive rights in connection with such additional issues. The Board of Directors has discretion in connection with the price and the other terms of the issue of such additional shares.

Variability of Dividends

The cash available for dividend to shareholders is a function of numerous factors, including AltaGas' financial performance, the impact of interest rates, electricity prices, natural gas and NGL prices, debt covenants and obligations, working capital requirements and future capital requirements. Dividends may be reduced or suspended entirely depending on the operations of AltaGas and the performance of its assets.

The market value of AltaGas shares may deteriorate if AltaGas is unable to meet its dividend targets in the future, and that deterioration may be material.

Changes in Legislation

Environmental and applicable operating legislation may be changed in a manner which adversely affects AltaGas through the imposition of restrictions on its business activities or by the introduction of regulations that increase AltaGas' operating costs thereby indirectly affecting AltaGas and potentially reducing dividends to shareholders.

Income tax laws relating to AltaGas may be changed in a manner which adversely affects shareholders.

Debt Service

AltaGas or its affiliates may, from time to time, finance a significant portion of their operations through debt. Amounts paid in respect of interest and principal on debt incurred by these entities may impair the ability to satisfy any obligations under its indebtedness held by AltaGas directly or indirectly. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Ultimately, this could reduce dividends to shareholders.

Loans to AltaGas or its affiliates are subject to customary covenants and financial tests which may in certain circumstances restrict AltaGas' ability to make dividends to shareholders.

Refinancing Risk

Each of the credit facilities has a maturity date, on which date absent replacement, extension or renewal, the indebtedness under the respective credit facility becomes repayable in its entirety. To the extent any of the credit facilities are not replaced or extended on or before their respective maturity dates or are not replaced, extended or renewed for the same or similar amounts or on the same or similar terms, AltaGas' ability to fund ongoing operations and pay dividends could be impaired.

Operating Risk

As AltaGas continues to grow and diversify its energy infrastructure businesses, the risk profile of AltaGas may change. Operating entities may enter into or expand business segments where there is greater economic exposure and more "at risk" capital. AltaGas' expectation of higher returns from these businesses justifies the level of risk. In addition AltaGas enters into these businesses on the basis that these risks can be actively managed.

Current operations are subject to the risks normally associated with the operation and development of natural gas and power systems and facilities, including mechanical failure, physical degradation, operator error, manufacturer defects, sabotage, terrorism, failure of supply, weather, wind or water resource deviation, catastrophic events and natural disasters. The occurrence or continuation of any of these events could increase AltaGas' costs and reduce its ability to process, transport, deliver or distribute natural gas or generate or deliver power.

AltaGas does not operate certain facilities, including the power plant from which power is generated under the PPAs. Failure by the operators of these facilities to operate at the cost or in the manner projected by AltaGas could negatively affect AltaGas' results.

Facility Throughput

AltaGas' extraction and field gathering and processing facilities process natural gas from the WCSB and its transmission facilities transport natural gas, ethane and NGLs from the WCSB. Throughput at these facilities is dependent on a number of factors, including the level of exploration and development activity within the WCSB, the long-term supply and demand dynamics for natural gas, ethane and NGLs and the regulatory environment for market participants. These factors may result in AltaGas being unable to maintain throughput at its facilities. Consequently, AltaGas may be exposed to declining cash flows and profitability arising from reduced natural gas, ethane and NGL throughput and from rising operating costs.

Market Risk

AltaGas is exposed to market risks resulting from movements in commodity prices and interest rates. AltaGas seeks to manage its exposure to these risks through the use of various physical and financial instruments.

AltaGas' Commodity Risk Management Policy details the parameters used to measure, monitor and report commodity price risks. It also includes risk management guidelines and objectives, risk tolerance and approved products. This policy prohibits the use of physical and financial instruments for speculative purposes.

Composition Risk

The extraction business is influenced by the composition of natural gas produced in the WCSB and processed at AltaGas' facilities. The composition of the gas stream has the potential to vary over time due to factors such as the level of processing done at plants upstream of AltaGas' facilities and the composition of the natural gas produced from reservoirs upstream of AltaGas' facilities.

Electricity Prices

AltaGas' revenue from sales of power in Alberta are subject to Alberta electricity market factors such as fluctuating supply and demand, which may be affected by weather, customer usage, economic activity and growth. AltaGas reduces its exposure to floating electricity prices by locking in margins with financial instruments and signing fixed-price sales arrangements with end-use customers for terms of up to 8 years. All of the power from the Bear Mountain Wind Park is contracted to BC Hydro under a 25-year Electricity Purchase Agreement at a set price which increases annually by 50 percent of the Canadian Consumer Price Index.

Interest Rates

AltaGas is exposed to interest rate fluctuations on variable rate debt. Interest rates are influenced by Canadian and global economic conditions beyond AltaGas' control. As part of its effort to mitigate the risk exposure associated with interest rate fluctuations, AltaGas monitors its level of fixed to variable rate debt and from time to time enters into interest rate swaps. AltaGas' target is to have approximately 70 to 75 percent of its debt at fixed interest rates.

Regulatory

AltaGas' businesses are subject to regulation in the jurisdictions in which they carry on business. Changes in the regulatory environment may be beyond AltaGas' control and may significantly affect AltaGas' businesses, results of operations and financial conditions. Pipelines and facilities can be subject to common carrier and common processor applications and to rate setting by the regulatory authorities in the event an agreement on fees or tariffs cannot be reached with producers. Power facilities are subject to regulatory approvals and regulatory changes in tariffs, market structure and penalties. AUI and Heritage Gas operate in regulated marketplaces where regulatory approval is required for the regulated returns that provide for recovery of costs and a return on capital.

Counterparty and Credit Risk

AltaGas is exposed to credit-related losses in the event that counterparties to contracts fail to fulfill their present or future obligations to AltaGas. AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas seeks to reduce counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits on clients, both prior to providing products or services and on a recurring basis. In addition, AltaGas seeks to include credit mitigation clauses in its contracts which allow for 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 has credit risk relating to numerous industrial, commercial and institutional counterparties. AltaGas seeks to avoid excessive concentration of risk associated with any particular industry or counterparty by diversifying its counterparties.

Collateral

AltaGas is able to obtain unsecured credit limits from its counterparties in order to lock in base load electricity margins and also to procure natural gas supply and services for its energy services business. If counterparties' credit exposure to AltaGas exceeds the unsecured credit limits granted, AltaGas may have to provide collateral in the form of letters of credit. AltaGas mitigates this risk through negotiation of contractual terms with counterparties related to unsecured credit, and diversification of electricity sales and natural gas purchases among a number of counterparties. Through accepted industry practices, AltaGas performs sensitivity analysis to ensure AltaGas has sufficient bank lines of credit available to withstand commodity price movements that may require AltaGas to provide counterparties with letters of credit.

REP Agreements

If AltaGas becomes insolvent or is in material default under the terms of the Rep Agreements for an extended period, effective ownership of the natural gas processing plant within the Harmattan Complex can be claimed by the original Harmattan Complex owners for a nominal fee. Accordingly, under these circumstances, AltaGas could lose its investment in the natural gas processing plant, excluding the Caroline Pipeline and various ancillary facilities that are owned 100 percent by AltaGas.

Harmattan Complex - Environment

Management has identified environmental issues associated with the prior activities of the Harmattan Complex. There are indications of significant groundwater and soil contamination resulting from the Harmattan Complex's prior activities. There is a risk that the costs of addressing these environmental issues could be significant. An environmental allocation agreement is in place with the former operator which allocates the liability. This agreement significantly reduces the soil contamination liability and eliminates the groundwater contamination liability to AltaGas.

Labour Relations

The operations and maintenance staff at the Younger Extraction Plant and some employees of AUI are members of a labour union. Labour disruptions could restrict the ability of the Younger Extraction Plant to process natural gas and produce NGLs or could affect AUI's operations and therefore could affect AltaGas' cash flow and net income.

Aboriginal Land Claims

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of the lands in western Canada. Such claims, if successful, could have a significant adverse effect on natural gas production and power development and generation in Alberta and British Columbia which could have a materially adverse effect on the volume of natural gas processed at AltaGas' facilities, the power produced by AltaGas facilities or on development of new facilities for gathering and processing, power generation or extraction and transmission.

Crown Duty to Consult First Nations

The federal and provincial governments in Canada have a duty to consult and, where appropriate, accommodate aboriginal people where the interests of the aboriginal peoples may be affected by a Crown action or decision. Accordingly, the Crown's duty may result in regulatory approvals being delayed or not being obtained.

Construction and Development

The development, construction and future operation of natural gas, natural gas distribution and power facilities can be affected adversely by changes in government policy and regulation, environmental concerns, increases in capital and construction costs, construction delays, increases in interest rates and competition in the industry. In the event that any one of these factors emerges, the actual results may vary materially from projections, including projections of costs, natural gas facility utilization or throughput, power production, future revenue and earnings.

The construction and development of AltaGas' natural gas, natural gas distribution and power projects and their future operations are subject to changes in the policies and laws of both Canadian and U.S. federal, provincial and state governments, including regulatory approvals and regulations relating to the environment, land use, health, culture, conflicts of interest with other parties and other matters beyond the direct control of AltaGas.

Weather and Long Term Wind or Hydrology Data

AltaGas' run-of-river power projects once built may be subject to significant variations in the stream flow necessary for power generation. AltaGas relies on hydrological studies and data to confirm that sufficient water flow is available to generate sufficient electricity to determine the economic viability of its projects. There can be no assurance that the long-term historical water availability will remain unchanged or that no material hydrologic event will impact the hydrologic conditions that exist within the watersheds. Annual and seasonal deviations from the long-term average can be significant.

AltaGas' Bear Mountain Wind Park, and its other wind power projects once built, may be subject to significant variations in wind which could affect the amount of power generated. AltaGas relies on wind studies and data to confirm that sufficient wind flows are available to generate sufficient electricity to determine the economic viability of its projects. There can be no assurance that the long-term historical wind patterns will remain unchanged. Annual and seasonal deviations from the long-term average can be significant.

The utility and natural gas distribution business is highly seasonal, with the majority of natural gas demand occurring during the winter heating season, the length of which varies in each jurisdiction. Natural gas distribution revenue during the winter typically accounts for the largest share of annual revenue in the utility business. There can be no assurance

that the long-term historical weather patterns will remain unchanged. Annual and seasonal deviations from the long-term average can be significant.

Key Personnel

AltaGas' success has been largely dependent on the skills and expertise of its key personnel. The continued success of AltaGas will be dependent on its ability to retain such personnel. Costs associated with retaining key personnel could adversely affect AltaGas' business operations and financial results.

ENVIRONMENTAL REGULATION

The natural gas industry, utility industry and the power generation industry are subject to environmental regulation pursuant to local, provincial, state, territorial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry and power industry operations. Due to the highly toxic and corrosive nature of sour gas, numerous extra regulatory precautions are applied to sour gas wells, processing facilities and pipelines. Environmental legislation can affect the operation of facilities and limit the extent to which facility expansion is permitted. In addition, provincial, territorial and federal legislation requires that facility sites and pipelines be abandoned and reclaimed to the satisfaction of provincial authorities and local landowners. A breach of such legislation may result in the imposition of fines, the issuance of clean-up orders or the shutting down of facilities and pipelines. It is possible that increasingly strict environmental laws, regulations and enforcement policies, and potential claims for damages and injuries to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future.

AltaGas takes its responsibility to protect the environment in which it operates very seriously. Its mandate is to fully comply with all environmental laws and regulations and to immediately and efficiently deal with any environmental incidents.

On April 26, 2007, the federal government proposed a plan entitled *"Turning the Corner"* for addressing greenhouse gas emissions. Elaboration on this plan was released March 10, 2008. Under this plan, facilities with greenhouse gas emissions exceeding a threshold level will be required to reduce their net greenhouse gas emissions intensity by 18 percent (relative to 2006 levels) by 2010. Compliance options include making operating improvements, participating in domestic emissions trading, buying a domestic offset to apply against the emission total, buying a Certified Emissions Reductions credit through the Kyoto Protocol's Clean Development Mechanism up to a prescribed maximum amount or contributing to an independent, third-party-administered fund that will invest in technology to reduce greenhouse gas emissions in Canada. In January 2010, Environment Canada listed a revised target to the "United Nations Framework Convention on Climate Change" as part of its submission for the "Copenhagen Accord". The submitted target represents a 17 percent greenhouse gas emissions reduction by 2020 relative to 2005 levels. Until the relevant legislation and regulations are enacted, AltaGas is not in a position to accurately determine the impact of any federal requirement to reduce greenhouse gas emission levels on its financial position.

On March 8, 2007 the Alberta government introduced the *Climate and Emissions Management Amendment Act* and the Specified Gas Emitters Regulation. The act came into force April 20, 2007 and the Specified Gas Emitters Regulation took effect July 1, 2007. The regulation applies to large emitter facilities producing a minimum of 100,000 tonnes of annual greenhouse gas emissions. Large emitters with 8 or more years of commercial operation must achieve annual emissions intensity reductions of 12 percent relative to a baseline emissions intensity established for the facility December 31, 2007. Annual emissions intensity reduction targets are phased in for newer facilities. Compliance options include making operating improvements, buying or developing an Alberta-based offset to apply against the emission total or contributing to the Alberta Government's new Climate Change and Emissions Management Fund that will invest in technology to reduce greenhouse gas emissions in the province. Owners of facilities that do not achieve the necessary reduction through operating improvements or offsets must pay $15 per tonne into the Climate Change and Emissions Management Fund or they may be subject to fines and penalties.

AltaGas has completed an assessment program of its field gathering and processing facilities to quantify the current levels of greenhouse gas emissions. Only the Harmattan Complex is subject to the Alberta regulation as its greenhouse emissions are above 100,000 tonnes per year. Management's calculations for emission intensity for 2010 indicate that the emissions from the Harmattan Complex are below its target intensity and therefore will not be subject to any penalty, but will qualify for credits.

AltaGas has completed an assessment of its facilities that do not qualify as large emitters under the Specified Gas Emitters Regulation and identified several opportunities to create offsets which could be used to mitigate some of the costs associated with greenhouse gas emissions from the Sundance B facility. Offsets from these facilities were used to reduce compliance costs for the 2010 reporting period and are expected to be available again for 2011.

The Sundance B Plant is a large emitter and TransAlta, as the facility owner, must ensure that facility complies with the Regulation. The Sundance B PPAs require TransAlta to take all reasonable steps as agreed to by ASTC, and at the cost of ASTC, to minimize any decrease in revenues or increase in the fixed or variable costs resulting from a Change in Law as that term is defined in the PPAs. AltaGas' share of the cost of compliance in 2010 was approximately $6.5 million.

On February 6, 2006 the Alberta government passed a regulation under the Alberta *Environmental Protection and Enhancement Act* related to control of mercury emissions from coal fired power plants. Holders of approvals to operate a coal-fired power plant were required to submit a proposal in accordance with the regulation for a mercury emissions control program at their coal-fired plant prior to April 1, 2007.

TransAlta submitted a mercury emission control program for the Sundance generating station to Alberta Environment on March 29, 2007. Based on discussions with Alberta Environment, TransAlta submitted a revised Proposal on April 3, 2009 that addressed Alberta Environment's comment. TransAlta selected Activated Carbon Injection (ACI) technology to meet the required 70% reduction in mercury emissions by January 1, 2011. TransAlta has advised that all civil and mechanical construction is now complete, as is the electrical tie-in. In addition, TransAlta has installed a Continuous Emission Monitoring System (CEMS) to ensure that the reductions are meeting the targeted levels. Testing was completed in December 2010 and the ACI and CEMS are now both fully operational. AltaGas will continue to follow up with TransAlta to assess the performance of the technology and seek to ensure that compliance is being met in an efficient and economic manner.

DIVIDENDS

AltaGas pays cash dividends on the shares on or about the 15th day of each month, or if that date is not a business day then the following business day, to shareholders of record on the 25th day of the previous month, or if that day is not a business day the following business day. Dividends on the Preferred Shares, Series A, are paid quarterly.

Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically by the Board of Directors, giving consideration to the ongoing sustainable cash flow as impacted by the consolidated net income, maintenance and growth capital and debt repayment requirements of AltaGas. The Corporation targets to pay a portion of its ongoing cash flow through regular monthly dividends made to shareholders.

AltaGas' dividends may be limited by its debt covenants under its credit agreements if a default or event of default exists or would be reasonably expected to exist upon or as a result of making such dividend. In the event of liquidation, dissolution or winding-up of the Corporation, the preferred shareholders have priority in the payment of dividends over the common shareholders.

For income tax purposes, 86.40 percent of the cash distributions declared in 2010 by the Trust prior to conversion to a corporation will be taxed as other income (investment income) and the remaining 13.60 percent as return of capital.

The following table summarizes the cash distributions of the Trust during 2008 and 2009. On July 1, 2010 the Trust converted to a corporation and AltaGas commenced paying dividends. The table shows the total of distributions paid by the Trust and dividends paid by AltaGas in 2010. The table also summarizes the cash dividends paid by AltaGas on the Preferred Shares, Series A issued in August 2010.

Canadian dollars per share	**2010**	**2009**	**2008**
Common shares (Trust units prior to Corporate Arrangement)	1.7400	2.1600	2.125
Preferred Shares, Series A	0.4589	-	-

DIVIDEND REINVESTMENT PLAN

AltaGas has adopted a Dividend Reinvestment and Optional Share Purchase Plan (the "Plan") for holders of AltaGas shares.

The Plan, as may be amended from time to time, provides eligible holders of AltaGas shares with the opportunity to reinvest the cash dividends paid by AltaGas on their shares towards the purchase of new AltaGas shares at a 5 percent discount to the Average Market Price (as defined below) of the shares on the applicable dividend payment date (the dividend reinvestment component of the Plan). The Plan also provides AltaGas shareholders who are enrolled in the dividend reinvestment component of the Plan with the opportunity to purchase new AltaGas shares at the Average Market Price (with no discount) on the applicable dividend payment date (the optional cash payment component of the Plan). Each of the components of the Plan is subject to prorating and other limitations on availability of new AltaGas shares in certain events.

The "Average Market Price", in respect of a particular dividend payment date, refers to the arithmetic average (calculated to four decimal places) of the daily volume weighted average trading prices of AltaGas shares on the TSX for the trading days on which at least one board lot of AltaGas shares is traded during the 10 business days immediately preceding the applicable dividend payment date. Such trading prices will be appropriately adjusted for certain capital changes (including AltaGas share subdivisions, AltaGas share consolidations, certain rights offerings and certain dividends).

No brokerage commissions will be payable in connection with the purchase of AltaGas shares under the dividend reinvestment component of the Plan or optional share purchase component of the Plan and all administrative costs under the Plan are borne by AltaGas. Proceeds received by AltaGas upon the issuance of additional AltaGas shares under the Plan will be used by AltaGas for future acquisitions, capital improvements and working capital. Shareholders resident outside of Canada are not entitled to participate in the Plan. Upon ceasing to be a resident of Canada, shareholders will be required to terminate their participation in the Plan.

On July 1, 2010, in connection with the Corporate Arrangement, AltaGas amended and restated the Plan effective with the August 16, 2010 dividend payment. The regular component of the Plan remained in effect.

MARKET FOR SECURITIES

The following chart provides the reported high and low trading prices and volume of Trust units traded by month from January to June 2010 and shares from July to December 2010 as reported by the TSX:

Month	High	Low	Volume
January	$19.29	$18.15	5,887,258
February	$18.79	$17.97	4,765,768
March	$18.89	$17.80	7,180,976
April	$18.73	$17.14	7,772,868
May	$17.73	$16.28	7,430,297
June	$18.76	$17.10	7,619,430
July	$20.43	$18.25	9,477,038
August	$20.75	$19.41	5,546,955
September	$21.50	$19.65	5,367,275
October	$22.27	$20.14	4,535,192
November	$21.23	$20.04	6,015,238
December	$22.55	$20.26	6,476,540

In addition, the Corporation’s Preferred Shares, Series A are traded on the TSX under the symbol ALA.PR.A commencing in August 2010. The following table sets forth the monthly price range and volume traded for AltaGas’ Preferred Shares, Series A from August to December 2010 as reported by the TSX:

Month	High	Low	Volume
August	$25.52	$25.19	1,759,983
September	$26.14	$25.49	486,755
October	$26.00	$25.43	280,736
November	$26.25	$25.65	232,696
December	$26.08	$25.00	270,016

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following table summarizes selected financial information for the last three financial years:

Year ended and as at December 31 *($ millions unless otherwise indicated)*	**2010**	**2009**	**2008**
Revenue			
Gas	1,064.3	1,098.9	1,643.2
Power	261.6	188.5	223.5
Utility[(1)]	151.7	43.5	-
Corporate	1.6	18.7	12.9
Intersegment Eliminations	(125.1)	(81.3)	(62.8)
	1,354.1	1,268.3	1,816.8
Net revenue			
Gas	312.7	327.2	334.1
Power	101.8	102.2	129.0
Utility[(1)]	71.9	13.0	-
Corporate	1.6	18.6	12.9
Intersegment Elimination	(2.5)	(4.4)	0.4
	485.5	456.6	476.5
EBITDA	243.8	251.5	258.7
- per share (basic)	$2.99	$3.20	$3.76
Net income	97.2	141.3	163.6
- per share (basic)	$1.19	$1.80	$2.38
Funds from operations	195.0	202.3	216.8
- per share (basic)	$2.39	$2.58	$3.15
Total assets	2,751.7	2,628.9	2,132.3
Total debt	904.5	1,014.7	565.3

Note:

(1) AltaGas acquired this business in October 2009.

CREDIT RATINGS

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities and are indicators of the likelihood of payment and of the capacity and willingness of a company to meet its financial commitment on an obligation in accordance with the terms of an obligation.

S&P and DBRS are rating agencies that provide credit ratings. These rating agencies' ratings for debt instruments range from a high of AAA to a low of D. Both rating agencies also provide credit ratings for preferred shares. S&P ratings for preferred shares range from a high of P-1 to a low of D. DBRS ratings for preferred shares range from a high of Pfd-1 to a low of D. S&P also assigns a corporate rating which ranges from a high of AAA to a low of D.

S&P rates AltaGas BBB with a Stable outlook. DBRS rates AltaGas BBB with a stable trend.

According to the DBRS rating system, debt securities rated BBB are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present 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.

According to the S&P rating system, an obligor rated BBB has 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 commitments. 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.

On August 10, 2010, S&P and DBRS commenced rating of AltaGas' preferred shares with an S&P rating of P-3H and DBRS rating of Pfd-3.

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

A P-3 rating by S&P is the third highest of eight categories granted by S&P. According to the S&P rating system, while securities rated P-3 to P-5 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.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by AltaGas within the most recently completed financial year, or before the most recently completed financial year but which are still material and are still in effect, are the following:

- $75,000,000 Extendible Revolving Term Credit Facility Credit Agreement. This is an unsecured three-year extendible revolving credit facility with Canadian Imperial Bank of Commerce and the Toronto Dominion Bank maturing on June 30, 2013. AltaGas may borrow by way of letter of credit, prime loans, U.S. base rate loans, LIBOR loans or bankers' acceptances on the credit facility. Borrowing on the facility bear fees and interest at rates relevant to the nature of the draw made;
- $600,000,000 Extendible Revolving Term Credit Facility Credit Agreement. This is an unsecured extendible revolving three-year credit facility with Royal Bank of Canada, Canadian Imperial Bank of Commerce, the Toronto Dominion Bank, Bank of Montreal, The Bank of Nova Scotia, Alberta Treasury Branches, National Bank of Canada, Canadian Western Bank, and the Hong Kong and Shanghai Banking Corporation maturing on June 30, 2013. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made;
- Trust Indenture between AltaGas and Computershare Trust Company of Canada dated July 1, 2010 related to the issuance and sale of debentures pursuant to AltaGas' medium-term note program;
- Utility Group $130 million Extendible Revolving Term Credit Facility with a syndicate of Canadian chartered banks which was restated and amended on November 17, 2010. The Utility Group unsecured extendible revolving credit facility with a syndicate of five banks was upsized to $200 million and its term was extended by three years to mature on November 17, 2013. Borrowings on the facility can be made by way of prime loans, U.S. base rate loans, letters of credit, bankers' acceptances or LIBOR loans.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

AltaGas Ltd. is not aware of any material interest, direct or indirect, of any director or officer of AltaGas Ltd., any director or officer of a corporation that is an insider or subsidiary of the Corporation, or any other insider of the Corporation, or any associate or affiliate of any such person, in any transaction since the commencement of AltaGas' last three completed financial years, or in any proposed transaction, that has materially affected or would materially affect the Corporation or any of its subsidiaries.

LEGAL PROCEEDINGS

AltaGas Ltd. is not aware of any material legal proceedings to which the Corporation or its affiliates is a party or to which their property is subject.

INTERESTS OF EXPERTS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, 1000, 440-2nd Ave. S.W., Calgary, Alberta T2P 5E9. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including directors and officer's remuneration and indebtedness, principal holders of AltaGas' securities, options to purchase AltaGas' securities, and interests of insiders in material transactions, where applicable, is contained in AltaGas' 2011 Information Circular, which is expected to be filed on or about March 18, 2011 in connection with the Annual Meeting of shareholders to be held April 20, 2011.

Additional financial information is contained in AltaGas' consolidated financial statements for the year ended December 31, 2010 and management's discussion and analysis contained in the 2010 Annual Report of the Corporation.

The Corporation routinely files all required documents through the SEDAR system and on its own website. Internet users may retrieve such material through the SEDAR website www.sedar.com. AltaGas' website is located at www.altagas.ca, but AltaGas' website is not incorporated by reference into this Annual Information Form.

TRANSFER AGENTS AND REGISTRARS

The registrar and transfer agent for the shares and the Preferred Shares is Computershare Trust Company of Canada, 600, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

The registrar and trustee for AltaGas' medium-term notes is Computershare Trust Company of Canada, 710, 530-8th Avenue S.W., Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

EFFECTIVE DATE

Unless otherwise specifically herein provided, the information contained in this Annual Information Form is stated as at December 31, 2010.

SCHEDULE A: AUDIT COMMITTEE MANDATE

I. Constitution

The Board of Directors of AltaGas Ltd. ("AltaGas" or the "Company") has established an Audit Committee (the "Committee"). Such committee shall be in compliance with the guidelines for corporate governance of The Toronto Stock Exchange ("TSX") and any regulatory or legal authority having jurisdiction over AltaGas.

The Committee shall supervise the audit of AltaGas' financial records and will ensure the adequacy and effectiveness of its policies and procedures regarding AltaGas' financial reporting, internal accounting, financial controls, management information and risk management.

II. Membership

Following each annual meeting of shareholders of AltaGas, the Board shall elect from its Members, not less than three (3) Directors to serve on the Committee (the "Members"). The Members and the Chair of the Committee are nominated and elected by the Board. Every Audit Committee Member must be:

- A Director of the Company
- Independent, and
- Financially literate.

No Member of the Committee shall be an officer or employee of the Company or any other subsidiary or affiliate of AltaGas. Any Member may be removed or replaced at any time by the Board and shall cease to be a Member upon ceasing to be a Director of the Company. Each Member shall hold office until the Member resigns or is replaced, whichever first occurs.

The Board will appoint a Member as Chair of the Committee on an annual basis.

The Corporate Secretary of AltaGas shall be secretary to the Committee unless the Committee directs otherwise.

III. Meetings

The Committee shall convene no less than four times per year at such times and places designated by its Chair or whenever a meeting is requested by a Member, the Board, or an officer of the Company. A minimum of twenty-four (24) hours notice of each meeting, plus a copy of the proposed agenda, shall be given to each Member. The Corporate Secretary and Members of management shall attend whenever requested to do so by a Member.

A meeting of the Committee shall be duly convened if two Members are present. Where the Members consent, and proper notice has been given or waived, Members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities as permit all persons participating in the meeting to communicate adequately with each other, and a Member participating in such a meeting by any such means is deemed to be present at that meeting.

In the absence of the chair of the Committee, the Members may choose one (1) of the Members to be the chair of the meeting.

The external auditor will be given notice of and be provided the opportunity to attend every meeting of the Committee.

The Audit Committee will hold in camera sessions with management, the internal and external auditors as may be deemed appropriate by the Members.

Minutes shall be kept of all meetings of the Committee by the Corporate Secretary or designate of the Corporate Secretary.

IV. Duties and Responsibilities

The Committee shall, as permitted by and in accordance with the requirements of the *Canada Business Corporations Act*, the Articles and By-Laws of the Company and any legal or regulatory authority having jurisdiction, periodically assess the adequacy of procedures for the public disclosure of financial information and review on behalf of the Board and report to the Board the results of its review and its recommendation regarding all material matters of a Financial Reporting and Audit nature, including, but not limited to the following main subject areas:

a) Financial Statements, including Managements Discussion and Analysis;
b) Reports to Shareholders and others;

c) Annual and Interim Press releases regarding financial results;
d) Internal controls;
e) Audits and reviews of financial statements of AltaGas and its subsidiaries;
f) Filings to securities regulators;
g) Review and approval of issuer's hiring policies re: current and former partners and employees of the external auditor;
h) Pre-approve non-audit work undertaken by the external audit firm;
i) Accounting and Auditing Irregularity Reporting Policy; and
j) Commodity risk management and related policies.

The Committee shall ensure satisfactory procedures for receipt, retention and resolution of complaints and for the confidential, anonymous submission by employees regarding any accounting, internal accounting controls or auditing matters.

The full Board will be kept informed of the Committee's activities by a report at each regular meeting of the Board.

The Committee will review the relevance and adequacy of this Mandate on at least an annual basis and will provide recommendations to the Governance Committee of the Board.

V. External Auditor

The Audit Committee shall recommend the appointment of the external auditor annually. Once appointed by the Shareholders, the external auditor shall report directly to Audit Committee.

The Audit Committee shall pre-approve all non-audit services provided by the external auditor, and shall have direct responsibility for overseeing the work of the external auditor engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services, including the resolution of disagreements between the external auditor and management.

VI. Relations with Management

The Committee will ensure that it coordinates its activities with the CFO on audit and financial matters and will:

- Meet regularly with Management to discuss areas of concern;
- Review and assess the quality of the executives involved in financial reporting process; and
- Ensure Management provides adequate funding to the Committee so that it may independently engage and remunerate the Auditor and any advisors.

VII. Committee Timetable

The major activities of the Committee will be outlined in an annual Schedule.

AltaGas Ltd.
1700, 355 - 4th Avenue S.W.
Calgary, AB T2P 0J1
Tel: 403-691-7575
Fax: 403-691-7576
www.altagas.ca