ALTAGAS LTD.

Annual Information Form

For the year ended December 31, 2013

Dated: March 10, 2014

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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 *"Overview of the Business"*, including with respect to the expected in-service date of a third cogeneration facility at the Harmattan Complex, and under the heading *"Overview of the Business – AltaGas' Strategy"*, including with respect to: expectations for the WCSB; expectations for the optimization of existing assets and through the development of new infrastructure, including energy export opportunities; expectations for power and distribution opportunities; and expectations for the cost of natural gas in North America. In addition, forward-looking statements in respect of the strategies applicable to each of AltaGas' business segments are set forth under the following sub-headings:

- *"Gas – Business Strategy"*, including in respect of the demand for natural gas, the viability of the WCSB, the demand for processing infrastructure, AltaGas' ability to capitalize on supply and demand fundamentals for natural gas and NGLs, the impact of the Co-stream Facility on utilization at the Harmattan Complex and opportunities to acquire or build gathering and processing infrastructure or tie-in new wells and increase volumes and capture operating synergies, the ability of AltaGas to capitalize on growing natural gas production in northeast British Columbia and northwest Alberta, the impact of the Gordondale Facility on capitalizing on liquids-rich gas and providing stable cash flows and the expected utilization thereof;

- *"Power – Business Strategy"*, including in respect of opportunities to expand the Blythe Energy Center, the potential to serve the CAISO and the DSW markets from the Blythe Energy Center, expectations regarding the cost and impact of the Northwest Projects, the expected timing of the commissioning and in service date of the Forrest Kerr Project, expected timing of the completion and in service dates of each of the McLymont Creek Project and the Volcano Creek Project, the anticipated impact of the Sundance B facility on profitability, opportunities to expand the Parkland gas-fired peaking facility, the in-service date of a third cogeneration facility at the Harmattan Complex, the timing of expansion of the Parkland gas-fired peaking facility, the impact of North American demand for cleaner energy sources and regulatory changes on the ability to develop and own additional power generation, the opportunity to capitalize on the demand for RECs in North America and the impact of the potential addition of LNG export facilities on power generation demand.

Finally, forward-looking statements in relation to AltaGas' business and business prospects are set forth under the following additional headings:

- *"General Development of AltaGas' Business – Historical Development"* under the following sub-headings:
  - *"Development of the Gas Business"*, including in respect of the impact of the Co-stream Facility on utilization at the Harmattan Complex, the intention to pursue LPG and LNG export opportunities through AltaGas Idemitsu LP and the expected in service date of the second expansion project for the Cold Lake natural gas transmission system;
  - *"Acquisition of Petrogas"*, including in respect of the impact of the acquisition of an interest in Petrogas on opportunities for LPG exports;
  - *"Development of the Power Business"*, including in respect of the expected commissioning and in service date of the Forrest Kerr Project and the expected cash flows to be derived therefrom and the timing of construction and in service dates of the McLymont Creek Project and Volcano Creek Project;

- *"Business of the Corporation"* under the following sub-headings:
  - *"Gas Business – Extraction and Transmission"*, including in respect of the impact of commodity prices or operating costs on NGL extraction, the utilization of the Harmattan Complex resulting from the completion of the Co-stream Facility, options regarding the Porcupine Hills pipeline and the expected in service date of the second expansion project for the Cold Lake natural gas transmission system;

- *"Gas Business – Field Gathering and Processing"*, including in respect of how AltaGas may underpin capital commitments, expectations regarding natural gas prices and demand for gathering and processing facilities in the WCSB associated with the drilling for liquids-rich gas and the associated gas from oil-targeted drilling and AltaGas' competitiveness in the midstream marketplace;

- *"Power Business"*, including in respect of expectations for growth through renewable energy projects and gas-fired generation opportunities, including cogeneration, expectations regarding the sufficiency of coal reserves at the Highvale Mine for the Sundance B plant, intentions with respect to the wind development projects in the U.S., the timing of commencement of commercial operations at the Northwest Projects, the timing of development and construction of the Log Creek and Kookipi Creek run-of-river hydroelectric projects, expectations regarding the cost characteristics of the Sundance B plant, the ability to generate further growth for the power infrastructure business with its renewable energy portfolio, the supply-demand balance for power in Alberta, the timing of development and intentions with respect to the development of AltaGas' hydroelectric and wind power development projects in Canada and the United States;

- *"Utilities Business"*, including expectations regarding AUI's annual growth in service sites, AUI's PBR formula and the capital tracker, expectations regarding AUC approval of AUI's PBR Phase II application and the effect of the AUC Generic Cost of Capital proceeding, in respect of the potential for Heritage Gas to apply to the NSUARB for increases to the RDA limit, AltaGas' belief in Heritage Gas' ability to continue to expand its customer base in Nova Scotia, expectations regarding increases in Heritage Gas' annual natural gas deliveries and its ability to access natural gas supplies sufficient to serve all its customers as it grows, expectations regarding the negotiated settlement process for PNG's 2013 revenue requirements and the effect of the Generic Cost of Capital Proceeding on PNG, expectations regarding an expansion of PNG's Western System transmission line, expectations regarding utilization of PNG's compressor stations at Vanderhoof and Telkwa, expectations regarding LNG Partners, LLC current status and resultant expectations regarding full utilization of the Western System, the Inuvik Gas pursuit of alternative energy sources given the decline of natural gas reserves of the Ikhil Joint Venture, expectations regarding the revenue generated by SEMCO Gas' MRP surcharge and expectations regarding SEMCO Gas' recovery of deferred amounts under the Valve Replacement Program, expectations regarding SEMCO Gas' application for updated rates, the ability of Cook Inlet production to meet ENSTAR supply needs, the possibility that prospective Alaska LNG exports could meet ENSTAR supply needs, expectations regarding the working capacity of the CINGSA Storage Facility and expectations regarding CINGSA filings with the RCA regarding rates**.**

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 business 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 these cautionary statements.

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 Idemitsu LP**" means AltaGas Idemitsu Joint Venture Limited Partnership;

"**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;

"**AUH(US)**" means AltaGas Utility Holdings (U.S.) Inc., a corporation formed under the laws of Delaware and an indirect wholly-owned subsidiary of AltaGas;

"**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;

"**BCUC**" means British Columbia Utilities Commission;

"**Blythe Energy Center**" means the gas-fired 507 MW Blythe Energy Center located near Blythe, California;

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

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

"**CAISO**" means the California Independent System Operator;

"**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;

"**CINGSA**" means Cook Inlet Natural Gas Storage Alaska, LLC;

"**CINGSA Storage Facility**" means the in-field storage facility in the Cook Inlet area of Alaska owned and operated by CINGSA;

"**Corporate Arrangement**" means the arrangement, under the provisions of section 192 of the CBCA, involving, among others, AltaGas, the Trust, AltaGas Holding Trust, the General Partner, AltaGas Holding Limited Partnership No. 1 and AltaGas Holding Limited Partnership No. 2, pursuant to which the business of the Trust was reorganized into a corporation effective July 1, 2010;

"**Co-stream Facility**" means the connection of the Harmattan Complex to the NGTL system and the related NGL extraction equipment to process up to 250 Mmcf/d of natural gas at the Harmattan Complex to recover ethane and NGLs;

"**CNG**" means compressed natural gas;

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

"**CPI**" means the Canadian Consumer Price Index;

"**DBRS**" means DBRS Limited;

"**Degree Day**" means the amount that the daily mean temperature deviates below 15 degrees Celsius at AUI, below 18 degrees Celsius at Heritage Gas and below 65 degrees Fahrenheit at SEMCO Gas and ENSTAR, such that a one degree difference equates to one Degree Day;

"**DEI**" means Decker Energy International Inc.;

"**DSW**" means the Desert Southwest Region of the Western Area Power Administration;

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

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

"**ENSTAR**" means the Alaska natural gas distribution business conducted by SEMCO Energy under the name ENSTAR Natural Gas Company;

"**EPA**" means electricity purchase agreement;

"**Forrest Kerr Project**" means the 195 MW run-of-river hydroelectric project, one of the three run-of-river hydroelectric projects in northwest British Columbia that are the Northwest Projects and include the Forrest Kerr Project, the McLymont Creek Project and Volcano Creek Project;

"**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 Holding Limited Partnership No. 1 and AltaGas Holding Limited Partnership No. 2;

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

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

"**Gordondale Facility**" means the Gordondale Gas Processing Facility in the Gordondale area of the Montney reserve area approximately 100 km northwest of Grande Prairie, Alberta;

"**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 combined Harmattan gas processing facility and the Harmattan extraction plant and associated facilities;

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

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

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

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

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

"**km**" means kilometre;

"**LNG**" means liquefied natural gas;

"**LPG**" means liquefied petroleum gas;

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

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

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

"**McLymont Creek Project**" means the 66 MW run-of-river hydroelectric project, one of the three run-of-river hydroelectric projects in northwest British Columbia that are the Northwest Projects and include the Forrest Kerr Project, the McLymont Creek Project and Volcano Creek Project;

"**MGP**" means manufactured gas plant;

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

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

"**MPSC**" means the Michigan Public Service Commission;

"**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;

"**NEB**" means the National Energy Board;

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

"**Northeast System**" means the PNG(NE) distribution utility in the northeast part of British Columbia;

"**Northwest Projects**" means the three run-of-river hydroelectric projects in northwest British Columbia, the Forrest Kerr Project, McLymont Creek Project and Volcano Creek Project;

"**Nova Chemicals**" means NOVA Chemicals Corporation;

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

"**NTL**" or "**Northwest Transmission Line**" means the 344 km, 287 kilovolt transmission line being constructed by BC Hydro from the Skeena substation near Terrace, British Columbia to a new substation near Bob Quinn Lake, British Columbia;

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

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

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

"**Pembina**" means Pembina Infrastructure and Logistics LP;

"**Petrogas**" means Petrogas Energy Corp.;

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

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

"**PBR**" means performance based regulation;

"**PNG**" means Pacific Northern Gas Ltd.;

"**PNG(NE)**" means Pacific Northern Gas (N.E.) Ltd.;

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

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

"**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;

"**RCA**" means the Regulatory Commission of Alaska;

"**RDA**" means Revenue Deficiency Account;

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

"**SCE**" means Southern California Edison;

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

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

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

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

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

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

"**SEMCO**" means Semco Holding Corporation;

"**SEMCO Energy**" means SEMCO Energy, Inc.;

"**SEMCO Gas**" means the Michigan natural gas distribution business conducted by SEMCO Energy under the name SEMCO Energy Gas Company;

"**SEMCO Shares**" means all of the issued and outstanding shares of common stock of SEMCO;

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

"**shareholders**" means the holders of Common Shares;

"**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;

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

"**United States**" or "**U.S.**" means the United States of America;

"**US GAAP**" means United States generally accepted accounting principles;

"**Volcano Creek Project**" means the 16 MW run-of-river hydroelectric project, one of the three run-of-river hydroelectric projects in northwest British Columbia that are the Northwest Projects and include the Forrest Kerr Project, the McLymont Creek Project and Volcano Creek Project;

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

"**Western System**" means PNG's regulated natural gas transmission and distribution utility in the west central portion of northern British Columbia; 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 TSX under the symbol "ALA".

At December 31, 2013 AltaGas had 122,305,293 outstanding Common Shares, 8,000,000 outstanding Series A Shares, 8,000,000 outstanding Series C Shares and 8,000,000 outstanding Series E Shares.

On April 4, 2013, AltaGas closed a public offering of 11,615,000 Common Shares at a price of $34.90 per Common Share for aggregate gross proceeds of approximately $405 million.

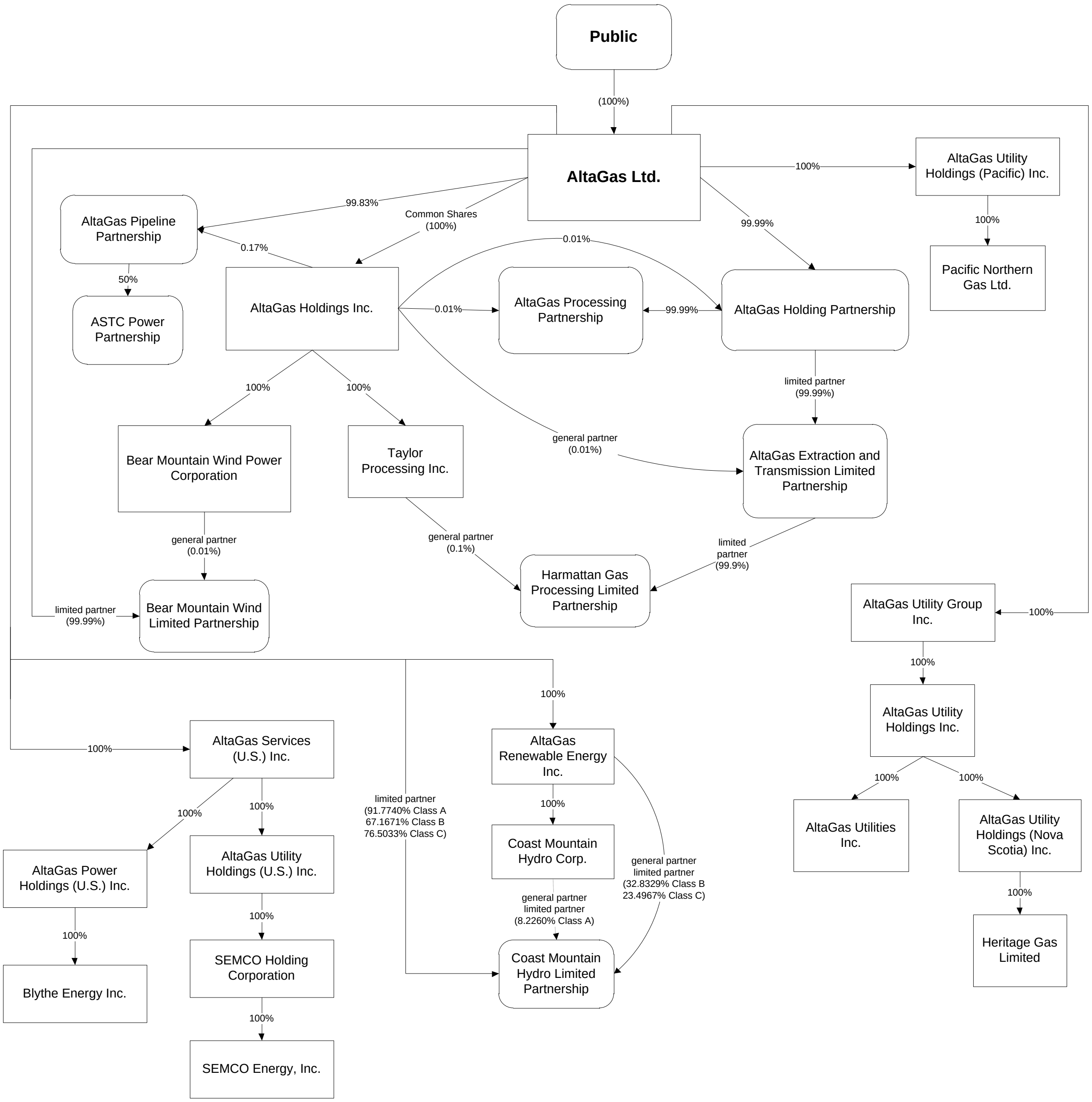
On October 1, 2013, AltaGas issued 2,801,905 Common Shares as part of the consideration for the acquisition of a 25 percent interest in Petrogas.

See *"General Development of AltaGas' Business – Historical Development – Acquisition of Petrogas"* and *"AltaGas Ltd. – Description of Capital Structure – Common 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. Effective January 1, 2012, AltaGas adopted US GAAP. All prior comparative information has been restated to comply with US GAAP.

SUBSIDIARIES

The following organization chart presents the name and the jurisdiction of incorporation of AltaGas' material subsidiaries as at December 31, 2013. 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 percent of the total consolidated assets or total consolidated revenues of AltaGas as at and for the year ended December 31, 2013.



Note:

(1) Each corporation listed above (other than Taylor Processing Inc., AltaGas Renewable Energy Inc., AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., AltaGas Power Holdings (U.S.) Inc., Blythe Energy Inc., Coast Mountain Hydro Corp, AltaGas Utility Holdings (Nova Scotia) Inc., Pacific Northern Gas Ltd., SEMCO Holding Corporation and SEMCO Energy, 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), each of AltaGas Renewable Energy Inc., Coast Mountain Hydro Corp. and Pacific Northern Gas Ltd. is a corporation incorporated under the *Business Corporations Act* (British Columbia), each of AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., AltaGas Power Holdings (U.S.) Inc., Blythe Energy Inc., and SEMCO Holding Corporation is a corporation formed under the laws of Delaware and SEMCO Energy, Inc. is a corporation formed under the laws of Michigan. Each partnership listed above (other than AltaGas Holding Partnership, Bear Mountain Wind Limited Partnership and Coast Mountain Hydro Limited Partnership) was established under the laws of Alberta. AltaGas Holding Partnership was established under the laws of Ontario and each of Bear Mountain Wind Limited Partnership and Coast Mountain Hydro Limited Partnership was established under the laws of British Columbia.

OVERVIEW OF THE BUSINESS

AltaGas is a diversified energy business with a focus on investing in and operating infrastructure to provide clean and affordable energy to its customers in North America. It does so through three business segments:

- Gas, which includes natural gas processing and transportation,
- Power, which includes power generation assets and power purchase arrangements for power supply, and
- Utilities, which include five regulated utilities across North America.

AltaGas has an enterprise value of approximately $9 billion. With the physical and economic links along the energy value chain, primarily from well head to burner tip, together with its experienced and talented workforce and its efficient, reliable and profitable assets, market knowledge and financial discipline, AltaGas has provided strong, stable and predictable returns to its investors. AltaGas focuses on maximizing the profitability of its assets, adding services that are complementary to its existing businesses, and growing through the acquisition and development of energy infrastructure.

Gas

The Gas business serves producers in the WCSB and transacts more than 2 Bcf/d of gas and includes natural gas gathering and processing, NGL extraction and fractionation, transmission, storage and natural gas marketing. The Gas business also includes the Corporation's 50 percent investment in the AltaGas Idemitsu LP along with the Corporation's investment in Petrogas. See *"General Development of AltaGas' Business – Historical Development – Development of the Gas Business"* and *"General Development of AltaGas' Business – Historical Development – Development of the Gas Business – Acquisition of Petrogas"*.

Gas gathering systems move natural gas from producing wells to processing facilities. The gas is then compressed for transportation. The extraction and field fractionation facilities reprocess natural gas to extract and recover ethane and NGLs. The transmission pipelines deliver natural gas and NGLs to distribution systems, end-users or other downstream pipelines. AltaGas buys and resells energy, provides gas transportation, storage and gas marketing for producers and sources gas supply to some of its processing assets.

The AltaGas Idemitsu LP is pursuing energy export opportunities including long term supply and sales arrangements to meet the growing demand for natural gas and LPG in Asia. On October 1, 2013, AltaGas purchased a 25 percent ownership interest in Petrogas, a leading integrated North American midstream company with an extensive logistics network consisting of over 1,500 rail cars and 24 rail and truck terminals, which provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities. On October 24, 2013, AltaGas announced that it would increase its effective ownership in Petrogas to 33⅓ percent by transferring its 25 percent interest to the AltaGas Idemitsu LP concurrently with the AltaGas Idemitsu LP acquiring an additional 41⅔ percent interest in Petrogas. The acquisition by the AltaGas Idemitsu LP was completed on March 1, 2014 on receipt of all applicable regulatory approvals and as a result Petrogas is owned one-third by each of AltaGas, Idemitsu Kosan Co.,Ltd. and its original shareholder. Idemitsu Kosan Co.,Ltd., AltaGas' partner in the AltaGas Idemitsu LP, is a global leader in the supply of energy, petroleum, lubricants and petrochemical products and services to Japan. Together, the three organizations bring key infrastructure assets and marketing expertise along with energy supply and access to markets in Asia.

Power

The Power business includes 1,096 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets. AltaGas owns 50 percent of the Sundance B PPA, giving it the rights to power output and ancillary services from coal-fired base-load generation until December 31, 2020.

In 2013, AltaGas acquired Blythe Energy Inc., which owns the Blythe Energy Center, a 507 MW natural gas-fired power plant and a 230 kilovolt 67-mile electric transmission line in southern California. Blythe Energy Center is fully contracted under a PPA with SCE until July 31, 2020, at which point the facility is uniquely positioned to potentially serve both the CAISO and the DSW market. The Blythe Energy Center is located on an owned 76-acre site. The facility is directly connected to Southern California Gas Company and interconnects with SCE and the CAISO via a 67-mile transmission line. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth.

Further generation is in various stages of construction including the three run-of river Northwest Projects, which consist of the 195 MW Forrest Kerr Project, 66 MW McLymont Creek Project, and 16 MW Volcano Creek Project. The 277 MW Northwest Projects are contracted with 60-year EPAs with BC Hydro which are fully indexed to CPI, as well as Impact Benefit Agreements with the Tahltan First Nation. The Forrest Kerr Project and Volcano Creek Project are expected to be in service in mid-2014 and late 2014, respectively, contingent on the availability of the NTL. The McLymont Creek Project is expected to be in service in mid-2015. AltaGas is also expanding its cogeneration fleet at the Harmattan Complex to 45 MW. AltaGas began engineering and procured the combustion turbine for the new 15 MW cogeneration facility to meet the increased power demand at the Harmattan Complex and increase sales to the Alberta power market. The new cogeneration facility is expected to be in service in the first half of 2015.

Utilities

The Utilities business is comprised of natural gas distribution utilities which serve approximately 550,000 customers in Canada and the United States. The Utilities business segment in Canada is comprised of AUI, the Alberta utility, PNG, the British Columbia utility and Heritage Gas, the Nova Scotia utility, as well as a one-third equity interest in Inuvik Gas in the Northwest Territories. The Utilities business segment in the United States is comprised of SEMCO Gas in Michigan, and ENSTAR and a 65 percent interest in CINGSA, both of which are in Alaska. The utilities are generally allowed the opportunity to earn regulated returns that provide for recovery of costs and a return on, and of capital from the regulator-approved capital investment base.

ALTAGAS' VISION AND OBJECTIVE

AltaGas' vision is to be a leading North American energy infrastructure company. The Corporation's overall objective is to generate superior economic returns by investing in low-risk, long-life energy assets. The Corporation focuses on assets underpinned by contracts with strong counterparties and regulated assets, both of which provide stable returns and long-life cash flows. The Corporation also focuses on growing its business through acquisitions and organic growth to further support dividend and capital growth. AltaGas believes that, in the long-term, the abundant supply of natural gas in North America and the worldwide demand for clean energy will provide opportunities for continued growth across all business segments.

ALTAGAS' STRATEGY

AltaGas invests in and operates energy infrastructure to provide clean and affordable energy to its customers in North America. AltaGas' strategy is to capitalize on the supply and demand for natural gas and the increasing demand for clean energy by owning and operating assets in gas, power and utilities. Integral to AltaGas' strategy is maintaining financial strength and flexibility, an investment grade credit rating and ready access to capital markets.

AltaGas operates in a safe, reliable manner with ongoing development of organizational capability to execute its strategy.

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

Gas – Business Strategy

AltaGas' Gas business serves customers primarily in the WCSB and transacts more than 2 Bcf/d of natural gas including natural gas gathering and processing, NGL extraction and fractionation, transmission, storage and natural gas marketing. 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 1.4 Bcf/d of raw field 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 supply management services to commercial end-users, buys and resells energy, provides gas transportation, storage and gas marketing for producers and sources gas supply to some of the processing assets. The Gas 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 1.6 Bcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin-based revenues;
- Four natural gas transmission systems with combined transportation capacity of approximately 0.5 Bcf/d and four NGL pipelines with combined capacity of 189,300 Bbls/d;
- More than 70 gathering and processing facilities in 32 operating areas in western Canada and a network of 6,600 km of gathering and sales lines that gather gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets;
- The Gordondale Facility with deep-cut extraction capabilities and the Co-stream Facility provide opportunity for the growth of liquids-rich gas processing and NGL extraction services. The facilities earn revenue on a take-or-pay or cost-of-service revenue model;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn hub in eastern Canada;
- A natural gas storage development project in Nova Scotia; and
- Natural gas marketing and gas transportation services to optimize the value of the infrastructure assets and meet customer needs.

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

- Increase throughput, utilization and efficiency of existing facilities;
- Provide cost-effective midstream services while delivering reliable and safe operations;
- 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.

The Gas business provides safe and reliable natural gas and NGL gathering, processing, extraction, transportation and storage services to its customers. The strategic focus is to increase profitability of the existing infrastructure, expand and add new infrastructure and redeploy assets to capitalize on increased exploration and drilling activities in the WCSB. AltaGas also focuses on long-term, fixed-fee, take-or-pay and cost-of-service contracts with strong counterparties to mitigate the impact of volume risk and increase stability of earnings. AltaGas is positioned to grow gas processing services to customers who are focused on liquids-rich natural gas production.

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

The supply and demand fundamentals for natural gas and NGLs provide significant growth opportunities in the Gas business. 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 AltaGas' extraction plants, with the exception of the Harmattan Complex and Younger Extraction Plant, depends on natural gas demand pull from residential, commercial and industrial usages inside and outside of western Canada, and gas liquids demand pull from the Alberta petrochemical, propane heating and Canadian oil and gas industries. Natural gas supply to the Younger Extraction Plant is dependent on the amount of raw natural gas processed at the McMahon gas plant which is based on the robust natural gas producing region of northeast British Columbia. Harmattan's raw natural gas supply is based on producer activity in west-central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities to consolidate and increase asset utilization and profitability. The Harmattan Complex is the only deep-cut and fractionation plant in the area. There is significant demand for gas processing capacity at the Harmattan Complex as a result of the high volume of liquids-rich gas being produced in the area. With the completion of the Co-stream Facility in 2012, 250 Mmcf/d of rich, sweet natural gas sourced from the west leg of the NGTL system can be processed using spare capacity at the Harmattan Complex to recover ethane and NGLs and increase utilization at the plant. The 20-year cost-of-service arrangement with Nova Chemicals for the Co-stream Facility adds long-life, stable cash flow that further strengthens AltaGas' business risk profile. See *"Business of the Corporation – Gas Business – Extraction and Transmission – Extraction – Harmattan Complex"*.

AltaGas also expects to see increased opportunities to acquire or build gathering and processing infrastructure from or on behalf of producers wishing to redeploy capital to exploration and production activities rather than dedicating to non-core activities such as gas processing. The Corporation also expects there to be opportunities to increase volumes by tying-in new wells and building or purchasing adjoining facilities and systems to create larger processing infrastructure to capture operating synergies and enhance its competitive advantage. The strategic location of some of its existing infrastructure is expected to allow the Corporation to capitalize on growing natural gas production in northeast British Columbia and northwest Alberta in response to the development of unconventional sources of gas such as Montney and Duvernay shale gas plays. In addition, AltaGas is able to relocate certain units quickly and cost effectively to respond to the changing processing needs of its customers since field gas compression and processing units are mostly skid-mounted. The Gordondale Facility contributes to customers' liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. The contractual underpinning of Gordondale provides stable cash flows. The Gordondale Facility is one of the largest sour gas plants built in Alberta in the last 15 years and was constructed in record time to meet producers' requirements in the area. Given the deep cut capability and strategic location of the facility, AltaGas expects utilization of the facility to increase over the coming months.

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

Power - Business Strategy

The Power business includes approximately 1,096 MW of generating capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets. A further 1,422 MW of power generation is in various stages of construction and development including 277 MW for the Northwest Projects.

The Power business includes:

- 507 MW of gas-fired generating capacity in California at the Blythe Energy Center;
- 353 MW of coal-fired generating capacity in Alberta through the Sundance PPAs;
- 117 MW of wind generation and a further 1,087 MW of wind power in various stages of development;
- 42 MW of gas-fired peaking plants in Alberta with a further 3 MW under construction;
- 35 MW of biomass generation;
- 30 MW of cogeneration capacity in Alberta with a further 15 MW under development;
- 12 MW of operating run-of-river generation, a further 277 MW under construction and 40 MW under development; and
- Commercial and industrial power sales in Alberta.

AltaGas continues to expand its footprint into the U.S. and at the end of 2013 owned 557 MW of generating capacity in the U.S. In 2013 AltaGas acquired the 507 MW Blythe Energy Center. The gas-fired generation capacity at the Blythe Energy Center is currently operating under a long-term PPA with SCE and serves the CAISO market. Due to the structure of the long-term PPA, the majority of the facility's revenues are derived from being available to produce and not actual production, therefore providing stable cash flows. The current capacity is contracted until July 31, 2020, at which point the facility is uniquely positioned to potentially serve both the CAISO and the DSW markets. The Blythe Energy Center is located on an owned 76-acre site which provides a significant geographic footprint for potential future expansion. The facility is directly connected to Southern California Gas Company and interconnects with SCE and the

CAISO via a 67-mile transmission line. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth. The Blythe Energy Center adds to the wind and biomass assets acquired in the U.S. in 2012.

The Busch Ranch Wind Project, which came into service in October 2012, is a 29 MW wind farm in Colorado with a 25-year PPA with the local utility, Black Hills/Colorado Electrical Utility Company, LP. AltaGas has a 50 percent interest in the Busch Ranch Wind Project.

AltaGas' biomass assets are held through DEI, a wholly owned subsidiary, whose primary assets are a 30 percent working interest in the 37 MW wood biomass power facility in Grayling, Michigan and a 50 percent working interest in the 48 MW wood biomass power facility in Craven County, North Carolina. Both biomass facilities have long-term PPAs.

At the end of 2013, the Power business was comprised of 425 MW of power generation capacity in Alberta. AltaGas' 50 percent ownership of the Sundance B PPAs represents the majority of its generation in Alberta. The PPAs provide AltaGas with the rights to power output and ancillary services from 353 MW of coal-fired base load generation until December 31, 2020. PPAs were established in 1999 under Alberta's program of power industry deregulation in order to separate ownership of the physical power generation assets from marketing of output.

In addition, AltaGas has 42 MW of gas-fired peaking power capacity in southern Alberta. In late 2010 the Corporation commissioned a 15 MW gas-fired cogeneration facility at the Harmattan Complex. In 2012 a second 15 MW cogeneration unit at the Harmattan Complex and a 3 MW gas-fired peaking plant at the Gordondale Facility were constructed and brought into service. This 72 MW of gas-fired capacity in Alberta provides fuel diversity to AltaGas' Power business and partially backstops outages at Sundance. The cogeneration facilities provide 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.

In 2014 capacity of the Parkland gas-fired peaking facility is expected to be expanded by 3 MW. A third 15 MW cogeneration facility is under development at the Harmattan Complex and is expected to be in-service in the first half of 2015.

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

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

AltaGas owns 114 MW of operating wind and run-of-river power generation in British Columbia. The 102 MW Bear Mountain Wind Park near Dawson Creek, British Columbia is an EcoLogo™ certified facility and generates RECs which AltaGas has retained. These credits are registered with the Western Renewable Energy Generation Information System and have been certified by the California Energy Commission, enabling AltaGas to sell them in the California market. In addition, Bear Mountain Wind Park has qualified for the federal government of Canada's ecoEnergy renewable initiative, which grants $10/MWh generated by the Bear Mountain Wind Park for 10 years and began on October 31, 2009. BMWLP entered into a long-term service agreement with the manufacturer of the wind turbines to operate and maintain the turbines. 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 for 25 years with 50 percent of the price escalated by CPI. The British Columbia power market is established by the government’s strategy to increase its green footprint and enter into EPAs with independent power producers. While the British Columbia power market is linked to some of the Northwest electric regions, namely Mid-Columbia and the California Oregon Border, the price received by BMWLP for power generated by the Bear Mountain Wind Park is driven by the contractual arrangement with BC Hydro. 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. Also included in the portfolio of power generation assets in British Columbia is a wholly owned 10 MW of run-of-river power generation facility and a

25 percent effective interest in a 7 MW run-of-river facility. All run-of-river power generation assets in British Columbia are also underpinned by long term EPAs with BC Hydro.

Growth in the Power business aligns with AltaGas' strategy of increasing earnings and cash flow stability and predictability. AltaGas' most significant undertaking to date is the construction of the aggregate 277 MW Northwest Projects. The Northwest Projects, estimated to cost approximately $1.0 billion, are underpinned by 60-year EPAs, fully indexed to CPI and have Impact Benefit Agreements with the Tahltan First Nation. The construction of the 195 MW Forrest Kerr Project is mechanically complete and commissioning is ongoing. The Forrest Kerr Project's in-service date is expected to be mid-2014, contingent on the availability of the NTL. Construction continues to progress well for the 16 MW Volcano Creek Project and the 66 MW McLymont Creek Project. These projects are expected to be in service in late 2014 and mid-2015, respectively.

AltaGas pursues opportunities in the Power business to enhance long-term shareholder value. The Corporation’s objectives are to:

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

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

The demand for renewable and clean generating capacity continues to be strong across North America, as the industry addresses climate change legislation and utilities are faced with renewable portfolio standards. Although coal-fired generation is still the dominant fuel source for power generation in North America, it is decreasing in market share based on economic fundamentals. Decreasing natural gas costs have made it such that gas-fired generation can compete on a marginal cost basis with coal in many parts of the United States. The economic benefit of gas-fired generation is amplified when capital costs and dispatch flexibility are accounted for.

The Sundance B facility is among the lowest cost producers of power in Alberta, uniquely 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 January 30, 2013 companies that offer the RRO were allowed to buy electricity up to 120 days in advance, as opposed to the 45-day lead time previously in effect. This change may reduce sudden price spikes for consumers. RRO providers submit their regulated rate proposals to the appropriate regulatory body for approval. The AUC regulates investor-owned utilities and approves RRO rates for the cities of Calgary and Edmonton and rural Alberta. The RRO pricing mechanism has lowered liquidity in the long-term market. While the changing market dynamics have presented opportunities for AltaGas to capitalize on the short-term price volatility, the RRO pricing mechanism results in fewer opportunities to enter into long-term hedges.

AltaGas' primary means of securing long-term power sales is through its commercial and industrial power retail business. AltaGas actively markets electricity and gas directly to end-users, enabling the Corporation to secure fixed-price sales at competitive market prices while earning fees associated with the administration of the metered data and billing. These commercial and industrial sales are typically for 3 to 5 year terms, offering AltaGas price certainty and a source of liquidity that has decreased in the wholesale market. Currently, AltaGas has approximately 125 MW of fixed-price sales to commercial and industrial customers for 2014, 100 MW for 2015, 30 MW for 2016 and 20 MW for 2017, all with average prices in the low $60's per MWh, excluding retail fees.

Opportunities to develop and own additional power generation are likely to arise with the growing North American demand for cleaner energy sources such as natural gas, hydroelectric and wind. Both the Canadian federal government’s stated policy to have coal-fired generators retire at the end of their useful economic lives and the Once-Through Cooling Water Policy for power generating facility intake structures in California may prompt additional opportunities to develop new clean power generation capacity. The Bear Mountain Wind Park, Busch Ranch, Grayling Generating Station, Craven County wood biomass power facility, Blythe Energy Center and the Northwest Projects under construction are all examples of AltaGas' strategy in action.

AltaGas has approximately 1,127 MW of renewable power under development, including 1,087 MW of wind power developments and 40 MW of run-of-river hydroelectric developments. AltaGas has 277 MW of run-of-river hydroelectric under construction and 18 MW of gas-fired power under construction. The wind projects are geographically dispersed in western North America, with 612 MW in Canada and 475 MW in the northern and western regions of the United States, while the run-of-river projects are located in British Columbia.

In 2013 there was considerable progress made in the natural gas industry in developing LNG projects in western Canada. The potential addition of LNG export facilities is expected to require additional power generation to support the LNG facilities and the increased economic and industrial activity expected to occur in the region. The strategic location of AltaGas' assets and operational expertise, along with a track record of collaborating with the First Nations in British Columbia, provide AltaGas a significant competitive advantage in its ability to capitalize on opportunities to increase its power generation portfolio to support LNG activities as they materialize.

Utilities - Business Strategy

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

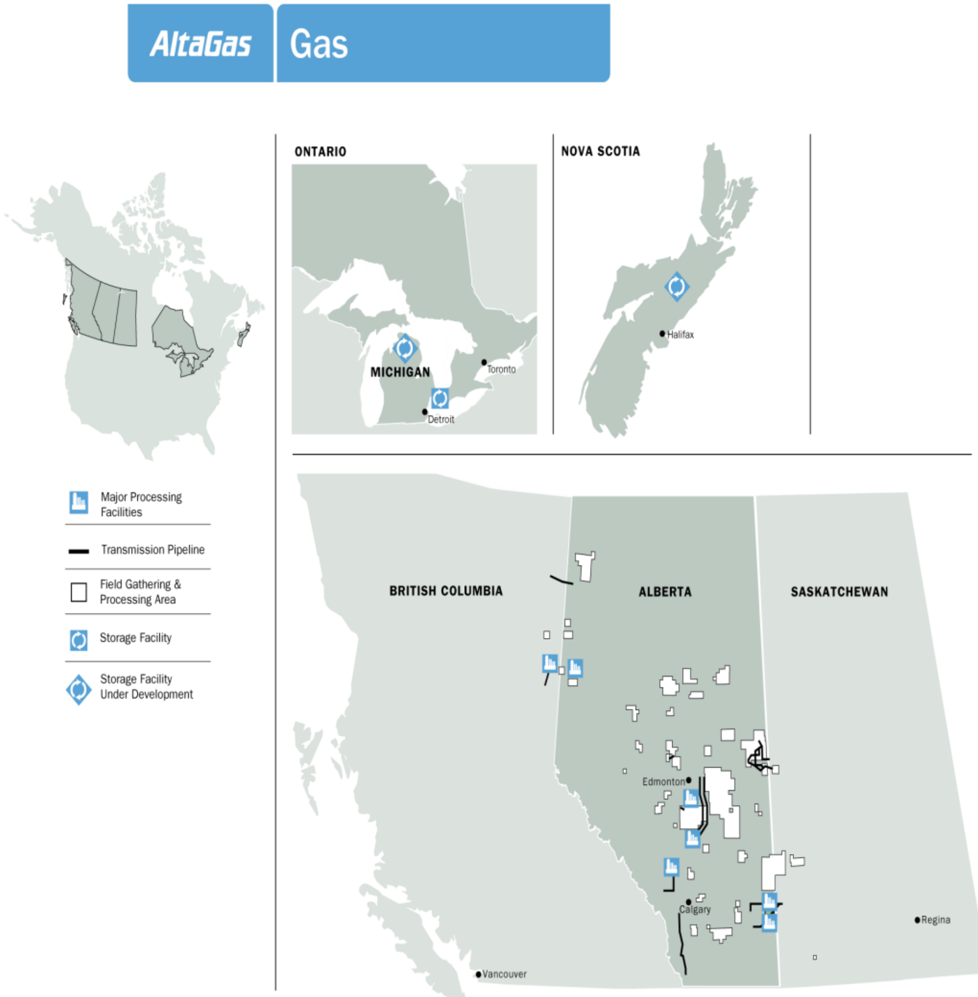
The utilities are underpinned by regulated returns and regulatory regimes that generally provide stable earnings and cash flows. The Utilities segment enhances the diversification of AltaGas' portfolio of energy infrastructure assets and strengthens the Corporation’s business profile, thus allowing the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

AUI in Alberta, PNG in British Columbia, Heritage Gas in Nova Scotia, SEMCO Gas in Michigan, and ENSTAR and CINGSA in Alaska are allowed the opportunity to earn regulated returns. This return on rate base comprises regulator allowed financing costs and ROE. In a cost of service regime and PBR regime, if actual costs are different from those recoverable through approved rates, the utility bears the risk of this difference other than for certain costs that are subject to deferral treatment. Inuvik Gas operates a natural gas distribution franchise in a regulatory environment where delivery service and natural gas pricing are market based.

While providing safe and reliable service, AltaGas pursues opportunities in the Utilities business to enhance long-term shareholder value and deliver value to its customers. The Corporation's objectives are to:

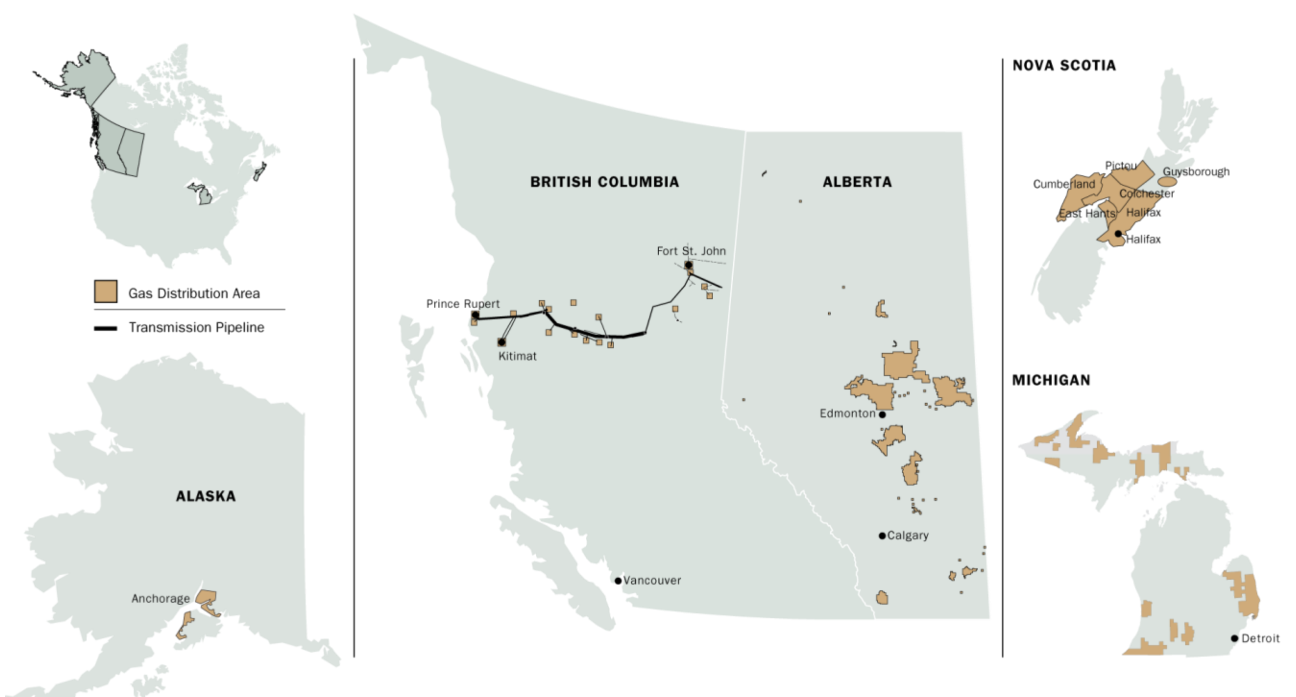
- Grow its existing utilities infrastructure through infill and expansion of services within current franchise or certificate areas;
- Continue multi-year system rejuvenation programs to maintain public and worker safety, and to ensure reliable and efficient long-term operation of its gas delivery systems;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

ALTAGAS' GEOGRAPHIC FOOTPRINT



AltaGas Power

AltaGas Utilities



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 2011, AltaGas completed expansions at the Alder Flats and Blair Creek gas processing facilities, adding a combined 18 Mmcf/d of capacity. AltaGas also acquired a 40 percent interest in the 40 Mmcf/d Marlboro facility in 2011.

In 2012, construction on AltaGas' 120 Mmcf/d deep cut Gordondale Facility was completed and it was commissioned. The plant is underpinned by a long-term contract with Encana and is equipped with liquids extraction facilities to capture the NGLs value for the producer.

In 2012, AltaGas completed expansions at the Blair Creek and Marlboro gas processing facilities, adding a combined 44 Mmcf/d of capacity. AltaGas also acquired a 50 percent interest in Quatro Resources Inc.'s midstream assets, including its 87 percent interest in the 75 Mmcf/d Gilby Gas plant.

In 2012, construction of the Co-stream Facility was completed which allows up to 250 Mmcf/d of rich, sweet natural gas sourced from the west leg of the NGTL system to be processed using spare capacity at the Harmattan Complex to recover ethane and NGLs. The Co-stream Facility provides an opportunity to increase utilization of the Harmattan Complex, providing producers with additional capacity to increase their netbacks on the west leg of the NGTL system.

On January 28, 2013, AltaGas entered into an agreement with Idemitsu Kosan Co.,Ltd. of Japan to form the AltaGas Idemitsu LP. The AltaGas Idemitsu LP is pursuing opportunities involving exports of LPG and LNG from Canada to Asia and other energy opportunities. AltaGas and Idemitsu each own a 50 percent interest in the limited partnership.

In 2013, AltaGas expanded its Cold Lake natural gas transmission system to deliver natural gas to provide steam to two heavy oil projects near Cold Lake, Alberta. The first expansion project was completed in fourth quarter 2013 and the second expansion project is expected to be in service in late 2014. The expansion projects are underpinned by long-term take-or-pay transportation agreements.

In December 2013, AltaGas sold ECNG Energy L.P., which conducted its energy management business.

In December 2013, AltaGas, entered into an agreement for the acquisition of the remaining 50 percent ownership interest in Alton Natural Gas Storage, which owns the proposed 10 Bcf Alton gas storage project near Truro, Nova Scotia. The transaction closed in February 2014. AltaGas acquired its initial 50 percent interest in Alton Natural Gas Storage pursuant to the acquisition of Landis Energy Corporation in 2010.

In February 2014, AltaGas sold the 35 Mmcf/d Ante Creek gas processing facility.

Acquisition of Petrogas

On October 1, 2013, AltaGas purchased a 25 percent ownership interest in Petrogas, a leading integrated North American midstream company. On October 24, 2013, AltaGas announced that it would increase its effective ownership in Petrogas to 33⅓ percent by transferring its 25 percent interest to the AltaGas Idemitsu LP concurrently with the AltaGas Idemitsu LP acquiring an additional 41⅔ percent interest in Petrogas, such that the AltaGas Idemitsu LP would have a 66⅔ percent interest in Petrogas. The acquisition by the AltaGas Idemitsu LP was completed on March 1, 2014 on receipt of all applicable regulatory approvals and as a result Petrogas is now owned one-third by each of AltaGas, Idemitsu Kosan Co.,Ltd. and its original shareholder.

Petrogas' extensive logistics network consists of over 1,500 rail cars and 24 rail and truck terminals, which provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities.

Development of the Power Business

In 2010 AltaGas announced the signing of a 60-year EPA with BC Hydro and an Impact Benefit Agreement with the Tahltan First Nation for the 195 MW Forrest Kerr Project. Construction of the Forrest Kerr Project is progressing well and is ahead of schedule and on budget. The project is mechanically complete, with commissioning to follow based on the availability of the NTL. 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 2011 AltaGas signed two 60-year fully CPI indexed EPAs with BC Hydro and two Impact Benefit Agreements with the Tahltan First Nation for the 66 MW McLymont Creek Project and the 16 MW Volcano Creek Project in the same area as the Forrest Kerr Project. Construction for the Volcano Creek Project and the McLymont Creek Project is well under way. The two projects are expected to be in service in late 2014 and mid-2015, respectively. The three Northwest Projects have a combined generating capacity of approximately 277 MW.

Effective January 1, 2012, AltaGas purchased the 25 MW of gas-fired peaking generators that formed part of the lease agreement between Maxim Power Corp. and AltaGas that was entered into in September 2004.

In 2012, AltaGas acquired DEI for $34.7 million. DEI is an independent power company whose primary assets are comprised of a 30 percent working interest in the 37 MW wood biomass Grayling Generating Station in Michigan and a 50 percent working interest in the 48 MW wood biomass Craven County power facility in North Carolina. Fuel supply for the biomass facilities include wood chips, mill residuals and other wood waste products from several suppliers. Power generated from these assets is fully contracted with long term PPAs.

In 2012, the Busch Ranch Wind Project was completed on budget and ahead of schedule. AltaGas acquired a 50 percent interest in the 29 MW wind farm in Colorado for US$25 million. The project has a 25 year renewable energy purchase agreement with Black Hills/Colorado Electric Utility Company, LP. The project was fully commissioned on October 15, 2012.

Effective July 10, 2012, AltaGas acquired the remaining 3 percent interest and now wholly owns the operating 10 MW McNair run-of-river hydroelectric generating facility located on the Sunshine Coast of British Columbia, near Port Mellon. AltaGas previously owned a 97 percent interest in the facility through the PNG acquisition. The McNair facility has been operating under a long-term EPA with BC Hydro since 2004. In addition to acquiring the operating facility, AltaGas acquired the exclusive option to obtain a 50 percent interest in the 45 MW Narrows Inlet run-of-river development projects, currently being developed by Renewable Power Corp. and Altaqua Renewable Power Corp.

In 2012, AltaGas completed the second 15 MW cogeneration facility at the Harmattan Complex. The 15 MW cogeneration facility provides steam for gas processing while providing clean base-load power to the Alberta power market.

In 2012, AltaGas disposed of its 60 percent interest in a 6 MW waste heat recovery unit near Sparwood, British Columbia.

In 2012, AltaGas disposed of 124 MW of wind development projects in Nevada.

In 2013, AltaGas acquired the Blythe Energy Center, a 507 MW gas-fired generation facility in southern California for US$515 million. The generating capacity is currently operating under a long-term PPA with SCE and serves the CAISO market.

In 2013, AltaGas disposed of 207 MW of wind development projects in the western U.S.

Development of the Utilities Business

Acquisition of PNG

In December 2011, AltaGas acquired 100 percent of the common shares of PNG for $224.0 million including approximately $86 million of assumed debt.

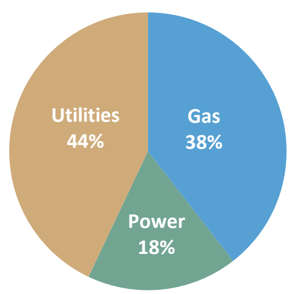
Acquisition of SEMCO

On August 30, 2012, AltaGas and AUH(US) closed the acquisition of SEMCO. AUH(US) acquired all of the issued and outstanding SEMCO Shares for aggregate consideration of US$1,156,000,000, before adjustment, including approximately US$371,000,000 in assumed debt. SEMCO Energy, a regulated public utility company headquartered in Port Huron, Michigan with natural gas distribution operations in Alaska and Michigan, is a wholly-owned subsidiary of SEMCO.

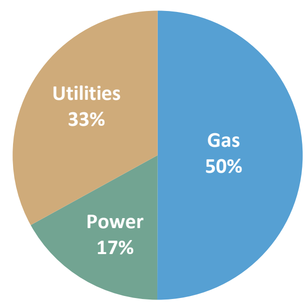
BUSINESS OF THE CORPORATION

AltaGas' net revenue for the 12-month period ended December 31, 2013 was $960.2 million compared to $664.4 million for the 12-month period ended December 31, 2012.

Net Revenue by Business for 2013 (1)(2)



Net Revenue by Business for 2012 (1)(2)



Notes:

(1) Net revenue is gross revenue less cost of sales.
(2) Excluding Corporate segment and intersegment eliminations

OPERATING BUSINESSES

AltaGas is comprised of three operating business segments: Gas, Power and Utilities. The Gas segment's activities include extraction and transmission, field gathering and processing and energy services. The Power segment consists of conventional coal-fired generation, gas-fired peaking plants and co-generation, wind power and hydroelectric. The Utilities segment comprises natural gas distribution. In addition, the Corporate segment consists of opportunistic investments, risk management contract results and revenues and expenses not directly identifiable with the operating businesses.

GAS BUSINESS

AltaGas' Gas business contributed net revenue of $368.9 million for the year ended December 31, 2013, representing approximately 38 percent of AltaGas' total net revenue before Corporate segment and intersegment eliminations.

GAS BUSINESS – 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. AltaGas operates EEEP, JEEP, the 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 licenced inlet capacity at these plants was 1,569 Mmcf/d at December 31, 2013.

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. NGLs 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 NGLs 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. This convention is not expected to change in the near future, as NGTL had applied to the NEB for amendments proposing that the extraction rights be transferred to the receipt shippers on the NGTL system however this application has been withdrawn.

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 one-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, 2013, approximately 69 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, 2013, approximately 31 percent of AltaGas' NGL production (14 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 re-injected 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 tables are a summary of AltaGas' capacity and the total production associated with extraction and fractionation plants in which AltaGas holds an interest:

Extraction or Fractionation Plant	Interest (%)	AltaGas' Inlet Processing Capacity (Mmcf/d)	Operated or Non-Operated
EEEP	48.67	190	Operated
Empress ATCO	7.20	79	Non-Operated
Empress Pembina	11.25	135	Non-Operated
JEEP	100.00	250	Operated
Younger	56.67	425	Operated
Harmattan Complex	100.00	490	Operated
Total[(1)]		**1,569**	

Note:

(1) Excludes Bantry fractionator products and field NGLs.

Total Liquids Production (Bbls/d)[(1)(2)]		
	2013	**2012**
NGLs	15,668	12,306
Ethane	33,885	26,025

Notes:

(1) Excludes Harmattan NGLs processed on behalf of customers, Bantry fractionator products and field NGLs.
(2) Average volumes for the fourth quarter.

Extraction - Empress ATCO Extraction Plant

AltaGas' ownership interest in the Empress ATCO extraction plant was 7.2 percent at December 31, 2013. 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 four 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.

Despite declining export volumes to the east from Alberta and increasing competition for gas supply at Empress, AltaGas has been able to utilize its Empress capacity by offering customers reliable energy services and access to markets.

Extraction - Empress Pembina Extraction Plant

AltaGas acquired a 10 percent interest in the Empress Pembina 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 licenced 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 75 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. AltaGas operates the facility which is located at Joffre, Alberta.

The plant is adjacent to 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 holds a 48.67 percent interest in EEEP. The remaining interest in the plant is held by ATCO Energy Solutions. AltaGas operates the plant. EEEP is directly connected to the Alberta Ethane Gathering System, and to Plains Midstream Canada's Co-Ed NGL pipeline, providing safe and reliable outlets for the plant products.

The plant has a licenced 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.

The processed gas from the facility supplies end-use markets in the city of Edmonton, Alberta. AltaGas' ethane production is sold to Nova Chemicals under a long-term fee-for-service contract. AltaGas sells its NGL production under a one-year evergreen marketing agreement based on the monthly average market price for NGLs.

Gas is supplied to EEEP under a gas supply agreement with NGTL which includes the right to extract liquids from all gas processed at EEEP.

Extraction – Younger Extraction Plant

AltaGas owns a 56.67 percent interest in the Younger Extraction Plant. The remaining interest is held by Pembina. 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. AltaGas also owns a 30 percent interest in a 250 Mmcf/d natural gas pipeline constructed in 2011 to bring liquids-rich gas from the Montney area of British Columbia to the Younger Extraction Plant.

The Younger Extraction Plant has a licence capacity to process up to 750 Mmcf/d of natural gas. AltaGas' share of the natural gas processing capacity is 425 Mmcf/d and Pembina'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 Pembina 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. Pembina 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.

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 the Rangeland 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 30 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. 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 CPI.

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.

The Co-stream Facility commenced commercial operations in November 2012. The Co-stream Facility allows the extraction of NGLs from gas in the west leg of the NGTL system using unused capacity in the NGL recovery units at Harmattan. AltaGas has a co-stream processing agreement with Nova Chemicals related to ethane and NGL extraction at Harmattan 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.

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 Pembina 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 Co-stream Facility has resulted in increased utilization at the plant, with the added benefit that the new equipment installed for the Co-stream Facility increases reliability and efficiency for both gas processing and Co-stream Facility customers.

Transmission – Business Description

AltaGas owns four natural gas transmission systems with transportation capacity of approximately 539 Mmcf/d and four NGL pipelines with combined capacity 189,300 Bbls/d.

The following table provides a summary of the gross capacity of AltaGas' transmission pipelines at December 31, 2013. 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]
Cold Lake	natural gas	East central Alberta	99.2	80 Mmcf/d	253	Operated
Kahntah[2]	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[3]	NGL	Southwest Alberta	100.0	11,600 Bbls/d	164	Operated
EDS	NGL	Central Alberta	100.0	90,000 Bbls/d	187.5	Operated
JFP	NGL	Central Alberta	100.0	50.000 Bbls/d	180	Operated
BDS	NGL	Central Alberta	100.0	37,700 Bbls/d	32	Non-operated

Notes:

(1) AltaGas operates the Cold Lake pipeline and has subcontracted out the operator function at its other pipelines.
(2) The Kahntah pipeline was taken out of service in 2011 due to low gas flows in the area, but remains available for use when demand for services is requested.
(3) The Porcupine Hills pipeline was shut-in in October 2013 due to the downstream discontinuance of a segment of the Plains Midstream Canada pipeline system; options are currently being evaluated.

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 southeast Alberta to the TransCanada Pipelines mainline at Burstall, Saskatchewan. The Suffield system is regulated by the NEB 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 170,080 GJ/d in 2013. 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, JFP and BDS

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 187.5-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 BDS is used to transport butane from Edmonton to Fort Saskatchewan. The pipeline is contract operated by, and the customer is, Keyera Energy Partnership. The BDS is a 32 km pipeline, with capacity of 37,700 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 is a single-shipper condensate pipeline. Until October 2013 the Porcupine Hills condensate pipeline delivered condensate from the Shell Waterton plant to the Town of Turner Valley for Shell Canada. In October 2013 the pipeline was shut-in due to downstream discontinuance of a segment of the Plains Midstream Canada pipeline system. Options regarding the pipeline are currently being evaluated.

Transmission – Cold Lake, Kahntah and Summerdale

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 36 receipt points and 37 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.

AltaGas expanded its Cold Lake natural gas transmission system in 2013 to deliver natural gas to provide steam to two heavy oil projects near Cold Lake, Alberta. The first expansion project was completed in fourth quarter 2013 and the second expansion project is expected to be in service in late 2014. The expansion projects are underpinned by long-term take-or-pay transportation agreements.

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 has been 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.

Transmission – Competition

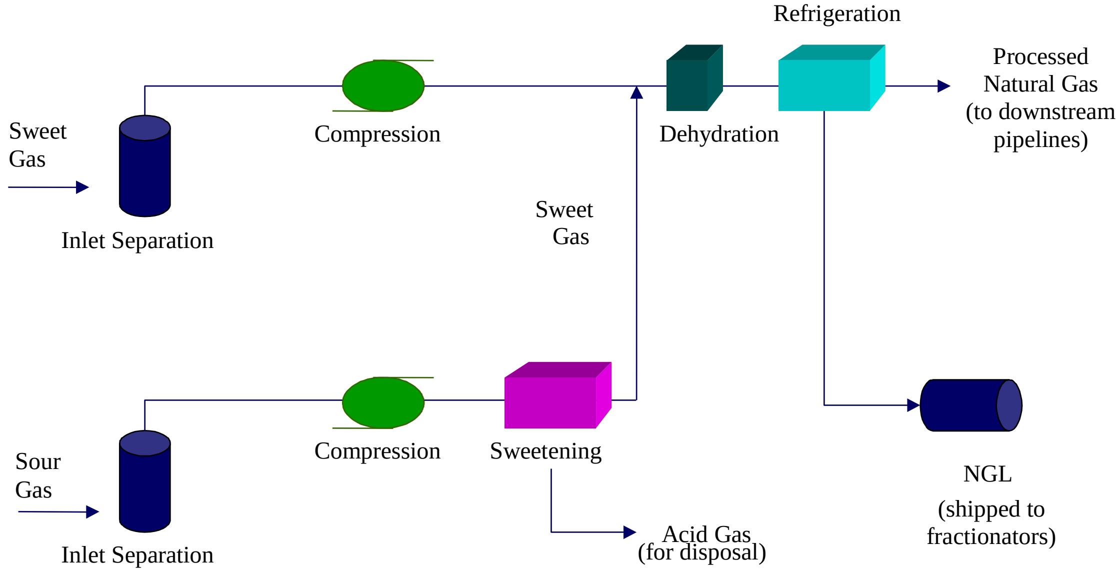
AltaGas competes with other midstream entities operating in the WCSB. AltaGas' transmission assets are well positioned to operate in a competitive environment and take advantage of their strategic locations and contract terms in order to compete with others. AltaGas continually investigates new pipeline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

GAS BUSINESS – FIELD GATHERING AND PROCESSING

The Field Gathering and Processing business consists of over 70 gathering and processing facilities in 32 operating areas located in western Canada and approximately 6,600 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 licenced processing capacity of 1.4 Bcf/d, of which one-third is capable of processing sour gas. AltaGas operates all but four 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 above under *"Gas Business – Extraction and Transmission"*. AltaGas has NGL extraction capability at 34 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

	2013	2012
Capacity (gross Mmcf/d)(1)(2)	1,384	1,384
Throughput (gross annual Mmcf/d)(2)	420	372
Capacity utilization (%)	30	27

Notes:

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

Average facility utilization increased to 30 percent in 2013 from 27 percent in 2012. AltaGas experienced increased throughput primarily due to a full year of operation at the Gordondale Facility, a full year of operation of the Blair Creek expansion and its interest in the 75 Mmcf/d Gilby Gas plant.

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 32 operating areas, AltaGas' Field Gathering and Processing business is not dependent on any one facility or operating area.

Field Gathering and Processing - Customers

In 2013 AltaGas conducted business with more than 250 customers in its operating areas. The Field Gathering and Processing business's top 10 customers represented approximately 8 percent of consolidated net revenue for 2013.

Field Gathering and Processing - Contracts

AltaGas gathers and processes natural gas under contracts with natural gas producers. There are approximately 900 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, Alberta Energy Regulator 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. Approximately 75 percent of contracts in place at December 31, 2013 were subject to annual price escalation related to changes in CPI. 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 2013 AltaGas processed an average of 420 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 BUSINESS – ENERGY SERVICES

Energy Services

One of the key functions of the energy services business is to support AltaGas' infrastructure businesses. The energy 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. Energy 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. Energy 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 energy 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' energy 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 other pipeline 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. 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.

In December 2013, AltaGas sold ECNG Energy L.P. which conducted its energy management business.

In December 2013, AltaGas, entered into an agreement for the acquisition of the remaining 50 percent ownership interest in Alton Natural Gas Storage, which owns the proposed 10 Bcf Alton gas storage project near Truro, Nova Scotia. The transaction closed in February 2014. AltaGas acquired its initial 50 percent interest in Alton Natural Gas Storage pursuant to the acquisition of Landis Energy Corporation in 2010.

Energy Services - Customers

AltaGas energy service customers are commercial, industrial, agricultural and institutional end-users in Ontario, Alberta, British Columbia, Quebec, New Brunswick, Nova Scotia, Saskatchewan and Manitoba. Customer retention rates are over 93 percent.

In its energy 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 2013.

Energy Services - Competition

In the energy 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 BUSINESS

AltaGas' Power business contributed net revenue of $177.1 million for the year ended December 31, 2013, representing approximately 18 percent of AltaGas' total net revenue before Corporate segment and intersegment eliminations.

The Power business is engaged in the sale of electricity and ancillary services in Alberta, British Columbia, California, Colorado, Michigan and North Carolina. At December 31, 2013, AltaGas had 1,096 MW of installed power capacity, comprised of 507 MW of gas-fired generation capacity at the Blythe Energy Center, 353 MW of power generation capacity through a 50 percent ownership interest in the Sundance B PPAs, 117 MW of wind power generation capacity, 42 MW of gas-fired peaking capacity, 30 MW of cogeneration capacity in Alberta, 35 MW of biomass generation and 12 MW of operating run-of-river hydroelectric power generation.

At December 31, 2013, AltaGas' 425 MW of installed power capacity in Alberta represented approximately 5 percent of Alberta's power generation.

Additional growth in the Power business will be driven by advancing AltaGas' significant and growing portfolio of renewable energy projects and pursuing further gas-fired generation opportunities. This was exemplified in 2013 through the purchase of the Blythe Energy Center, a 507 MW gas-fired generating facility in southern California. For the coming years, AltaGas has approximately 1,404 MW of renewable power generation projects in various stages of construction and development. The renewable power portfolio consists of 1,087 MW of wind power developments, 40 MW of run-of-river hydroelectric developments and 277 MW run-of-river hydroelectric under construction. The wind projects are geographically dispersed in western North America, with 612 MW in Canada and 475 MW in the northern and western regions of the United States, while the run-of-river projects are all located in British Columbia.

Through AltaGas'ongoing assessment of its wind development portfolio, management decided to dispose of its interest in approximately 207 MW of wind development projects in the western U.S. in 2013 due to the pending expiration of land tenure agreements, permitting constraints, and uneconomic development conditions.

Gas-Fired Generation

Effective May 16, 2013, AltaGas purchased the 507 MW Blythe Energy Center combined cycle power plant in southern California for US$515 million before adjustments for working capital. The facility utilizes gas-fired generation to produce power and heat. The heat is then captured in secondary steam generators, which produce additional power via a steam turbine, and increase the efficiency of the overall generation process. The power serves the CAISO market to cover periods of high-demand, primarily driven by the Los Angeles area. The facility employs proven Siemens technology and has a low base load heat rate in the range of 7,000 to 7,500 Btu/kWh, low emissions, responsive start times and flexible ramp rates. Due to the structure of the long-term PPA with SCE, the majority of the facility's revenues are derived from being available to produce and not actual production, therefore providing stable cash flow. The current capacity is contracted until July 31, 2020. The facility is directly connected to Southern California Gas Company and interconnects with SCE and the CAISO via a 67-mile transmission line. The facility is also interconnected with the El Paso Natural Gas system and is situated to reconnect to the DSW, providing market access optionality upon expiry of the PPA to serve both the CAISO and the DSW market. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth. Gas-fired generation is an efficient, environmentally responsible means of producing electricity and is expected to be an attractive area of potential growth for AltaGas' Power business.

AltaGas has 30 MW of cogeneration capacity in Alberta. In 2010, AltaGas commissioned a 15 MW cogeneration facility at the Harmattan Complex. 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 the Harmattan Complex from the waste heat in the exhaust gases from the turbine. In 2012, AltaGas completed a second 15 MW cogeneration facility at the Harmattan Complex. This facility has essentially the same configuration as the existing cogeneration facility and helps to meet the increased power demands at the plant as a result of the Co-stream Facility, with excess power being sold to the Alberta grid.

Currently plans are under development for the installation of a third 15 MW cogeneration facility at the Harmattan Complex, with completion expected in the first half of 2015.

AltaGas has 42 MW of gas fired peaking plants in Alberta. Effective January 1, 2012 AltaGas purchased the 25 MW gas-fired peaking generators that formed part of the lease agreement with Maxim Power Corp. In 2014 capacity of the Parkland gas-fired peaking facility is expected to be expanded by 3MW. 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.

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. 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. The units are grouped 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 ASTC Partnership income through equity accounting.

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 costs consist of 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 ASTC 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 2013. 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	2013	2012
Volume of power sold (GWh)(1)(2)	4,458	3,317
Average price received on the sale of power ($/MWh)(1)(2)	76.82	69.42
Alberta Power Pool average spot price ($/MWh)(1)	80.19	64.32

Notes:

(1) Annual average.
(2) Includes both Alberta and British Columbia sale of power.

Biomass Generation

In 2012, AltaGas acquired DEI, an independent power company whose primary assets are comprised of a 30 percent working interest in the 37 MW Grayling Generating Station in Michigan – a wood biomass power facility, and a 50 percent working interest in the 48 MW Craven County wood biomass power facility in North Carolina. Fuel supply for the biomass facilities include wood chips, mill residuals and other wood waste products from several suppliers. Power generated from these assets is fully contracted with long-term PPAs.

Wind Generation

AltaGas has 117 MW of wind generation with all electricity generated being sold under long-term contracts.

The 102 MW Bear Mountain Wind Park near Dawson Creek in British Columbia consists of 34 turbines, a substation and transmission and collector lines. It is connected to the 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 EPA at a set price which increases annually by 50 percent of CPI. BMWLP has retained the green attributes and RECs 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 RECs above a cumulative threshold amount.

In 2012, the Busch Ranch wind project was completed on budget and ahead of schedule. AltaGas acquired a 50 percent interest in the 29 MW wind farm in Colorado for US$25 million. The project has a 25-year renewable energy purchase agreement with Black Hills/Colorado Electric Utility Company, LP. The project was fully commissioned on October 15, 2012. In February 2013, AltaGas received a U.S. government grant of US$7.6 million for capital costs associated with the Busch Ranch wind project as a specified energy property under the *American Recovery and Reinvestment Act*. This grant was accrued against the capital cost of the facility.

AltaGas has a portfolio of 1,087 MW of wind power development projects. The wind projects are geographically dispersed in western North America, with 612 MW in Canada and 475 MW in the northern and western United States. AltaGas believes these assets will generate further growth for the power infrastructure business.

AltaGas has two wind development projects located in Manitoba, Reston and Yellowhead, and totalling 408 MW. These projects are mature projects that are eligible for future calls for power with Manitoba Hydro. AltaGas has completed most of the Environmental Assessment and has received an Interconnection Approval with the AESO for the 204 MW Glenridge wind development project in Alberta.

The 475 MW of wind development projects in the United States are comprised of properties at Walker Ridge, in California, Chateau Hills in New Mexico and Roughrider in North Dakota. AltaGas intends to continue development of these projects by conducting transmission, wind resource and environmental studies at these sites.

In 2013, AltaGas disposed of approximately 207 MW of wind development projects in the western U.S.

Hydroelectric Generation

In March 2010 AltaGas received its amended Environmental Assessment Certificate for the largest of its three northwest British Columbia run-of-river hydroelectric projects, the Forrest Kerr Project. In May 2010 AltaGas entered into a 60-year EPA with BC Hydro for the Forrest Kerr Project, as well as an Impact 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 NTL. The Forrest Kerr Project will be the anchor tenant for the NTL, along with the two smaller projects under construction by AltaGas in the same vicinity, the 66 MW McLymont Creek Project and the 16 MW Volcano Creek Project, which will both feed into the BC Hydro electrical system through Forrest Kerr.

In November 2011 AltaGas entered into two 60-year EPAs with BC Hydro for the McLymont Creek Project and the Volcano Creek Project, as well as two Impact Benefit Agreements with the Tahltan First Nation. The McLymont Creek Project has a capacity of 66 MW and is located 10 km west of the Forrest Kerr Project. The McLymont Creek Project will interconnect at the Forrest Kerr switchyard.

The Northwest 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 energy needs in an environmentally and socially responsible manner by offsetting the use of electricity generated from fossil fuels.

The 195 MW Forrest Kerr project is progressing well and is ahead of schedule and on budget. The Forrest Kerr Project is mechanically complete and commissioning is ongoing. The Forrest Kerr Project is expected to be in-service in mid-2014 contingent on the availability of the NTL. Construction for the two smaller projects, the 66 MW McLymont Creek Project and the 16 MW Volcano Creek Project, is also progressing well. Construction of Volcano Creek was able to be pulled ahead due the early mechanical completion of Forrest Kerr. The powerhouse building, weir and headrace canal have been completed. The Volcano Creek Project is expected to be in-service in late 2014, two years ahead of the initial schedule. Construction of the McLymont Creek bridge is completed and excavation of the power tunnel is 50 percent complete. The McLymont Creek Project is expected to be in-service in mid-2015. All three of the Northwest Projects hydro power generation assets in British Columbia are underpinned by long-term EPAs with BC Hydro, fully indexed to CPI.

Effective July 10, 2012 AltaGas now wholly owns the operating 10 MW McNair run-of-river hydroelectric generating facility located on the Sunshine Coast of British Columbia, near Port Mellon. AltaGas previously owned 97 percent of the facility through the PNG acquisition. The McNair facility has been operating under a long-term EPA with BC Hydro since 2004. In addition to acquiring the operating facility, AltaGas acquired the exclusive option to obtain a 50 percent interest in the 45 MW Narrows Inlet run-of-river development projects, currently being developed by Renewable Power Corp. and Altaqua Renewable Power Corp.

AltaGas has an effective 25 percent interest in a 7 MW run-of-river hydroelectric power generation facility on Scuzzy Creek, near Boston Bar, British Columbia which is under a 20-year EPA with BC Hydro until 2015. AltaGas also has two 10 MW run-of-river hydroelectric project development projects near Boston Bar, British Columbia: Log Creek and Kookipi Creek. Both the Log Creek and Kookipi Creek run-of-river hydroelectric projects are supported by 40-year EPAs with BC Hydro. 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.

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.

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 relatively strong in the spot market due to a combination of generator retirements and robust demand growth in the province and the supply demand balance is anticipated to remain tight over the medium term. AltaGas remains confident in the ongoing profitability of its power generation assets.

Wind power generated from both Bear Mountain and Busch Ranch is not currently exposed to power price volatility as the power generated is sold at a fixed price for 25 years, with escalation factors of 50 percent of CPI and 2 percent, respectively. The Blythe Energy Center is contracted by SCE under a long-term PPA until July 31, 2020. Power sold from the McNair run-of-river power generation facility is not exposed to power price volatility as the power generated is sold at a fixed price for 20 years escalated at 50 percent of CPI. Power sold from the Grayling Generating Station in Michigan and the Craven County wood biomass power facility in North Carolina is not exposed to market prices and is sold under long-term PPAs.

UTILITIES BUSINESS

AltaGas' Utilities business contributed net revenue of $434.7 million for the year ended December 31, 2013, representing approximately 44 percent of AltaGas' total net revenue before Corporate segment and intersegment eliminations.

The Utilities business owns utility assets that deliver natural gas to end-users in Canada (Alberta, British Columbia, Nova Scotia and the Northwest Territories) and the United States (Michigan and Alaska). The Utilities business in Canada is comprised of AUI, the Alberta utility business, PNG, the British Columbia utility business and Heritage Gas, the Nova Scotia utility business as well as a one third interest in Inuvik Gas. The Utilities business in the United States is comprised of SEMCO Energy, a regulated public utility company headquartered in Port Huron, Michigan with natural gas distribution operations in Alaska through ENSTAR and in Michigan through SEMCO Gas and a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska.

Regulatory Process

The Utilities business predominantly operates in regulated marketplaces where, as franchise or certificate holders, they are allowed the opportunity to earn regulated rates that provide for recovery of costs and a return on capital from the regulator approved capital investment base. Inuvik Gas operates a natural gas distribution franchise in a light-handed regulatory environment where delivery service and natural gas pricing are market based.

Canada

The distribution of natural gas in Alberta, British Columbia, Nova Scotia and the Northwest Territories is regulated by the AUC, the BCUC, the NSUARB and the NWTPUB, respectively. The AUC, BCUC and NSUARB's jurisdiction includes the approval of distribution tariffs for regulated distribution utilities which includes the rates charged and the terms and conditions on which service is to be provided by those utilities. Inuvik Gas is regulated on a complaint basis and sets its rates to be market competitive.

For Heritage Gas and PNG, the regulators approve distribution rates based on a cost-of-service regulatory model. Under this model, the regulators 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.

On February 26, 2010, the AUC initiated the Rate Regulation Initiative aimed at implementation of formulaic based regulation, also referred to as Performance Based or Incentive Regulation, for Alberta gas and electric distribution utilities. Commencing January 1, 2013 in Alberta, AUI is regulated under a PBR model. Under this model, revenues are set by formula. Specifically, revenues in each year are based on the last approved rates and increased each year by a formula reflecting inflationary increases less expected productivity improvements. Amounts determined under the formula may also be supplemented in the event of extraordinary events creating gains or losses outside management's control or for major capital projects not otherwise encompassed within the PBR formula. Regardless of which model is used, the regulators attempt to ensure the resulting tariffs are just and reasonable, provide incentives for investments, and are not unduly preferential, arbitrary, or unjustly discriminatory.

United States

SEMCO Energy's primary business is gas distribution and gas storage, and consists of the regulated storage, transmission, distribution and sale of natural gas to its customers. SEMCO Energy's gas distribution and gas storage, including the 65 percent ownership interest in CINGSA, accounted for approximately 99 percent of SEMCO Energy's 2013 consolidated operating revenues. SEMCO Energy has other businesses, including operations and investments in propane distribution, intrastate natural gas pipelines and an equity investment in a natural gas storage facility in Michigan. The gas distribution business purchases, transports, distributes and sells natural gas and related gas distribution services to residential, commercial and industrial customers and is SEMCO Energy's largest business segment.

The gas distribution business and the CINGSA Storage Facility are subject to regulation. The MPSC has jurisdiction over the regulatory matters related, directly or indirectly, to the services that SEMCO Gas provides to its Michigan customers. The RCA has jurisdiction over the regulatory matters related, directly or indirectly, to ENSTAR's service provided to its Alaska customers, including the CINGSA Storage Facility. These regulatory agencies have jurisdiction over, among other things, rates, accounting procedures and standards of service.

In Alaska and Michigan, the regulators approve distribution rates based on a cost-of-service regulatory model. Rates are set using the results from a historical test year plus known and measurable changes. Under this model, the regulators 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 regulators attempt to ensure that tariffs are just and reasonable, provide incentives for investments, and are not unduly preferential, arbitrary, or unjustly discriminatory.

Utilities Business Key Utility Metrics

The following table summarizes the allowed rate of return on equity and cost of debt for the Utilities business in addition to average net rate base for the Utilities business as at year end.

	2013	**2012**
Approved return on equity (%)		
Utilities Canada (average)	10.0	10.0
Utilities US (average)(1)	11.3	11.3
Approved return on debt (%)		
Utilities Canada (average)	6.1	6.5
Utilities US (average)(1)	5.6	5.6
Rate base ($ millions) (2)		
Utilities Canada	604.8	569.6
Utilities US (1) (3) (4)	773.0	741.0

Notes:

(1) AltaGas acquired SEMCO on August 30, 2012.
(2) Rate base is indicative of the earning potential of each utility over time. Approved revenue requirement for each utility is typically based on the rate base as approved by the regulator for the respective rate application. Depending upon the timing of the regulators decision with respect to rates, the amount of rate base utilized to determine rates charged may reflect historical levels.
(3) In U.S. dollars.
(4) Reflects 65 percent interest in CINGSA.

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 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 approximately 9 percent of the market served by member-owned natural gas cooperatives and municipally owned systems.

Within its existing franchise areas AUI averaged annual growth of 1.9 percent in 2011, 2.4 percent in 2012 and 1.92 percent in 2013. AUI currently expects annual growth in new service sites of approximately 2.0 percent for 2014 and thereafter.

AUI 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 AUI's franchise areas. 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.

In 2010, AUI began a multi-year system rejuvenation program to maintain public and worker safety and to ensure reliable and efficient long-term operation of AUI's gas delivery systems, many of which are in their fifth or sixth decade of service. AUI's capital expenditures for the years ended December 31, 2013 and 2012 are shown in the following table:

($ millions)	**2013**	**2012**
New business	6.4	7.3
System betterment and gas supply	13.9	12.4
General plant	6.7	7.0
Total	**27.0**	**26.7**

Operations

AUI's distribution system consists of 20,633 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 781 small and mid-sized metering and pressure regulating stations throughout AUI's distribution network. AUI operates its gas distribution systems through a network of 14 district offices.

In 2013, the total throughput of natural gas transported for three producers and delivered to 74,842 end consumer service sites had a total energy value of approximately 21.0 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 1,442 in 2013 and 1,703 in 2012. Of the 21.0 PJ of natural gas AUI delivered through AUI's system in 2013, 11.6 PJ was attributed to 60,660 non-demand service sites that received default gas supply under the regulated rate, 4.0 PJ to 14,130 non-demand service sites that received gas supply from natural gas retailers, 2.8 PJ to 52 demand-based service sites and 2.6 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[1]

(%)	**2013**	**2012**
Residential	54.9	55.4
Commercial	24.2	23.9
Rural[2]	17.0	16.9
Demand	3.9	3.8
Total	100.0	100.0

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, 2013, AUI held a total of 74 such franchises and agreements: 45 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 with its own operating agreement.

Franchises/Permits	**# of Agreements**	**% of Total Service Sites**	**Average Remaining Term**
Municipal Government Act Franchises	45	63.9	3.0
Indian and Northern Affairs Canada Permits	9	1.5	Varying
Gas Distribution Act Franchises	16	33.5	Perpetual
Métis Settlement Operating Agreements	4	1.1	0.5 years

The three largest municipalities served by AUI (City of Leduc, Town of Beaumont and Town of Drumheller) accounted for approximately 23 percent of AUI's total net revenue and 19 percent of energy delivered in 2013.

Seasonality

The natural gas distribution business in Alberta is seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. 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 Degree Days expected for the period. Temperature fluctuations impact the operating results of AUI.

	2013				**2012**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	1,958	126	580	2,103	2,103	97	534	1,924
Degree Days - normal	1,762	206	563	2,212	1,765	209	559	2,166

2013 AUI Regulatory Overview

In Decision 2012-237, issued September 2012, the AUC approved a revenue cap per customer formula for AUI. Under the formula, AUI's rates increase annually by inflation, measured through a composite index reflecting changes in the Statistics Canada generated Alberta Consumer Price Index and Average Weekly Earnings index for the twelve previous months ending June 30 of the previous year. For 2013, interim rates were approximately 2.65 percent higher than those approved for 2012.

In addition to the revenues under the formula, utilities under PBR may also apply for recovery of significant costs arising from circumstances outside their control, such as changes in law and natural disasters and/or directives initiated by Alberta Energy or the AUC ("Y Factor adjustments"). For 2013, AUI received approval for recovery of $3.6 million in Y Factor adjustments related to implementation of its Natural Gas Settlement System Code ("NGSSC") project required for compliance with AUC Rule 028, income tax timing differences and annual changes to applicable deferral accounts. AUI also obtained approval for recovery of capital tracker ("K Factor") amounts related to $11.5 million in specified pipe replacement, station refurbishment and gas supply investments.

For 2014, AUI's rates will increase under the formula, on average, by 3.32 percent. Interim rates for 2014 also include approved Y Factor adjustments for income tax timing differences, AUC/UCA Assessments, Intervener Hearing Costs and NGSSC project costs. A K Factor placeholder for recovery of 60 percent of AUI's total 2014 K Factor amount has also been approved on an interim basis, effective January 1, 2014. The K Factor amount reflects depreciation, interest and return on the full year 2013 K Factor investments, as well as $15.6 million in 2014 forecast expenditures. A final decision on the 2014 K Factor amounts is expected in Q3 2014.

In June 2013, AUI filed a 2013-2017 PBR Phase II Application to establish the rate design applicable throughout the PBR term. With the approval of the AUC, a negotiated settlement process was established, culminating in the filing of a Negotiated Settlement Agreement ("NSA") in November 2013 and endorsed by all stakeholders. As the NSA is subject to AUC review and approval, a final decision is not expected before the end of Q2 2014. In the interim, the rate design encompassed within the NSA was used in development of the rates approved effective January 1, 2014. The cumulative effect of the rate increase and rate design changes is approximately a 5 percent increase for Rate 1 (residential and small commercial) customers, a 4 percent decrease for Rate 2 (large general service) and Rate 3 (industrial/demand) customers and a 13 percent decrease for Rate 4 (irrigation) customers.

The AUC had suspended the proposed scope of 2013 Generic Cost of Capital ("GCOC") proceeding pending completion of the 2013 Capital Tracker and Utility Asset Disposition Review ("UADR") proceedings. With the issuance of both decisions, the GCOC proceeding resumed, with the filing of evidence by all parties on January 31, 2014. A hearing is scheduled to commence in May 2014. The decision, which will establish the return on equity and capital structures for all AUC regulated utilities for 2013, 2014 and, possibly, future years, is unlikely to be released before Q4 2014. In the interim, the AUC has approved continued use of the 2011 and 2012 ROE of 8.75 percent as a placeholder.

During 2013, the AUC also undertook a review of current regulatory practice and precedents related to the treatment of stranded assets, assets disposed of in the ordinary course of business and the early retirement of assets. The UADR also examined the treatment of costs related to retired assets, such as environmental clean-up costs. On November 26, 2013, the AUC issued Decision 2013-417. In the Decision, the AUC approved AUI's recovery of reclamation costs related to former production facilities exhausted in the provision of utility service. The reclamation costs included in AUI's 2010-2012 General Rate Application and AUI's base rates were previously approved only as placeholder amounts. The Decision also states the AUC does not consider any change in the current legislation or regulatory practice is required to give effect to recent Alberta Court of Appeal and Supreme Court of Canada decisions on asset dispositions.

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 through its distribution system 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, Nova Scotia.

As a greenfield operation, Heritage Gas has a small but increasing 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. At current prices, natural gas has a competitive price advantage compared to all alternative energy sources.

In 2013, Heritage Gas completed the construction of a CNG loading and unloading system which currently is not subject to rate regulation. This facility enables Heritage Gas to transport natural gas via specially designed tube trailers to facilities located beyond the economically feasible reach of traditional pipelines. This type of CNG system is new to Nova Scotia but it has been in operation in other regions of Canada for several years.

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

Potential customer meters 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 2013 there were approximately 11,000 potential customer meters of whom approximately 4,200 were commercial energy consumers and 6,800 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 11,000 potential customer meters, Heritage Gas had installed service lines to 5,482 customer meters over its years of operations, of which approximately 5,052 customer meters were activated by December 31, 2013. Heritage Gas is contemplating future development projects throughout its franchise area and expects to pursue these and other future growth opportunities that are contiguous to its current operations.

The following table illustrates the percentage of consumers who have access to the Heritage Gas system that have become customers of Heritage Gas.

Penetration rates (%)	2013	2012
Activated residential	37	32
Activated commercial	60	54
All customers	46	40

In 2013, Heritage Gas connected 723 new customers, compared to 756 in 2012.

Capital expenditures by Heritage Gas for the years ended December 31, 2013 and 2012 are shown in the following table:

($ millions)	**2013**	**2012**
New business	30.5	20.4
General plant	0.9	0.8
CNG	8.7	3.7
Total	40.1	24.9

In 2013 Heritage Gas invested $40.1 million to continue the expansion of its network. The major focus was the continued expansion in the Halifax Regional Municipality where Heritage Gas added 18 kilometres of network infrastructure and the expansion to a new franchise market in Pictou County. Included in the capital expenditure is $8.7 million toward the completion of the CNG loading and unloading system

From its inception in 2003 until 2011 Heritage Gas' actual revenues billed to customers were less than the revenue required to earn the regulated revenue requirement. Heritage Gas is allowed to accumulate up to a maximum of $50 million in a RDA for this shortfall. The RDA is a component of Heritage Gas' rate base upon which it earns a return. Heritage Gas may, if necessary, apply to the NSUARB for increases to the RDA account limit. Heritage Gas began drawing down the RDA in 2012.

The RDA for the years ended December 31, 2013 and 2012 is shown in the following table:

Revenue Deficiency Account		
($ millions)	**2013**	**2012**
	40.0	44.5

Operations

On December 31, 2013, Heritage Gas' distribution system consisted of approximately 350 km of pipeline mains infrastructure of which approximately 280 km was located in the Halifax Regional Municipality, approximately 60 km was located in Amherst and approximately 10 km was located in Oxford.

Heritage Gas purchases gas under negotiated contracts with wholesale gas marketers. During 2013, Heritage Gas entered into six new contracts to manage its gas supply needs and to provide stability during the winter months. The contracts have various ending dates ranging from February 28, 2014 to October 31, 2014. 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, which management believes will ensure that Heritage Gas has sufficient gas supplies to serve all its customers as it grows.

Seasonality

The natural gas distribution business in Nova Scotia is seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

Delivery rates for Heritage Gas are set based on the 20-year rolling average Degree Days expected for the application period. Temperature fluctuations impact the operating results of Heritage Gas.

	2013				**2012**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	1,405	126	645	1,925	1,213	86	685	1,813
Degree Days - normal	1,284	138	650	1,966	1,295	143	758	1,984

2013 Heritage Gas Regulatory Overview

On October 17, 2011 Heritage Gas reached an agreement with the active interveners to settle all matters related to its 2012 – 2014 GTA. The settlement agreement was presented to the NSUARB on October 17, 2011 and was approved on

November 24, 2011. The agreement results in an average annual rate increase of 8.25 percent, 6 percent, and 3 percent over the years 2012, 2013, and 2014 respectively.

The approved agreement includes allowed return on equity of 11 percent and cost of debt of 7.25 percent on a prescribed capital structure of 45 percent equity and 55 percent debt. Cost allocation and rate design matters were accepted as proposed by Heritage Gas for 2013.

In 2012 the NSUARB set a timeline for a regulatory hearing related to cost allocation and rate design for 2013. On June 16, 2012, Heritage Gas entered into a settlement agreement related to the cost allocation and rate design for different rate classes in 2013 and 2014, leaving the rate classes as they were originally structured. The settlement agreement confirmed the average rate increases approved by the NSUARB on November 24, 2011 effective January 1, 2013 and 2014. The NSUARB approved the settlement agreement on June 19, 2012.

In 2013 the NSUARB approved a unique rate for an extra-large customer located in Pictou County which will take service in Q1 2014.

PNG

On December 20, 2011, AltaGas acquired all of the outstanding common shares of PNG pursuant to a statutory plan of arrangement. PNG's head office is located in Vancouver, British Columbia and its principal operating office is located in Terrace, British Columbia. PNG's wholly owned subsidiary, PNG(NE) has its main operating offices in Fort St. John and Dawson Creek, British Columbia.

PNG owns and operates the Western System, a regulated natural gas transmission and distribution utility within the west central portion of northern British Columbia. PNG(NE) owns and operates the Northeast System, a distribution utility in northeast British Columbia. PNG also owns the 9.8 MW McNair Creek hydro-electricity generation facility, a non-regulated renewable energy business. See above under *"Power Business"*.

Substantially all of PNG's and PNG(NE)'s pipeline facilities are located across Crown land or privately-owned property under rights-of-way granted by the Crown or the owners in perpetuity or for so long as they are used for pipeline purposes. Approximately three kilometres of main pipelines and approximately nine kilometres of lateral transmission pipelines cross reserves established under the *Indian Act* (Canada), for which PNG has appropriate land rights. Compressor and metering stations are principally located on land owned by PNG. PNG owns its local offices in Terrace, Prince Rupert, Kitimat, Burns Lake, Smithers, Dawson Creek, Tumbler Ridge and Fort St. John and leases office space in a number of other communities in its service area and in Vancouver.

All of the property and assets of PNG and PNG(NE) are subject to the lien of a deed of trust and mortgage dated as of April 15, 1982 between PNG and Computershare Trust Company of Canada, as trustee, as amended and supplemented from time to time, under which PNG's secured debentures have been issued.

All of PNG's and PNG(NE)'s residential customers, most of their commercial customers and a number of their smaller industrial customers continue to rely on PNG and PNG(NE) for arrangement of their gas supply, and pay tariffs which include PNG/PNG(NE)'s gas supply commodity and delivery costs. The large industrial customers, the majority of small industrial customers and a number of commercial customers purchase their gas supply requirements from third party gas suppliers and contract for gas transportation service on the PNG and PNG(NE) pipeline systems. In addition, some of the smaller commercial customers purchase their gas supply requirements directly from gas marketers. Since the income is earned from the distribution of natural gas and not from the sale of the commodity, distribution margin is not adversely affected by this practise.

In the Western System service area there are few remaining candidates for conversion to natural gas in the existing building stock and limited opportunity remains to extend gas distribution into unserviced rural areas. However, in 2013 PNG commenced development of a project to expand the capacity of its transmission line by approximately 600 Mmcf/d. During the third quarter of 2013, PNG signed transportation reservation agreements with two parties to support the PNG expansion (the "Pipeline Looping Project" or "PLP"). These reservation agreements provide for cost recovery of development expenses incurred with respect to the PLP. Approximately $6 million of development activity for PLP was recorded in 2013, with such amounts recorded as accounts receivable until such time that a definitive decision is made to proceed with construction of the project. On July 24, 2013, the British Columbia Environmental Assessment Office issued an order accepting PNG's PLP into the environmental assessment process following PNG's filing of its project description. PNG expects to continue its environmental and consultation processes with a final investment decision on PLP expected in late 2015.

In the Northeast System service area, PNG(NE) continues to build out its distribution system to new communities and to capture new housing and commercial developments in its existing serviced communities.

PNG's capital expenditures for the years ended December 31, 2013 and 2012 are shown in the following table:

($ millions)	**2013**	**2012**
New business	3.8	2.6
System betterment and gas supply	6.1	4.6
General plant	2.3	1.7
Total	12.1	9.1

Operations

PNG's transmission pipeline system in the Western System service area connects with the British Columbia pipeline system operated by Spectra Energy near Summit Lake, British Columbia, and extends 587 km to the west coast of British Columbia at Prince Rupert. The pipeline between Summit Lake and Terrace has been partially paralleled, or looped, with a second line to increase throughput capacity. PNG also owns and operates over 300 km of lateral transmission pipelines extending into the various communities served by PNG, the most significant being dual lines extending approximately 57 km into Kitimat. The Western System distribution system is comprised of approximately 950 km of distribution pipelines.

Five compressor units maintain pressure on PNG's Western System transmission pipeline system: two located at Summit Lake and one each at Vanderhoof, Burns Lake and Telkwa. The total installed rating of the compressor units is 16.1 MW. The sustainable capacity of the transmission pipeline system, with the present compressor and looping configuration, is approximately 3,260 10^3m^3 per day. PNG deactivated its compressor stations at Vanderhoof and Telkwa, as well as 85 km of 10 inch pipeline and 53 km of 6 inch pipeline when the Methanex Corporation methanol/ammonia facility in Kitimat ceased operations. These facilities will continue to be maintained for potential future use, but are not forecast to be utilized in 2014. If service commences under the Gas Transportation Service Agreement with LNG Partners, LLC, the Western System would be at full capacity utilization. The cost to reactivate the facilities left idle when Methanex Corporation ceased operations in 2005 would be recovered from these incremental revenues. LNG Partners, LLC provided a notice of commencement in late 2012. However LNG Partners, LLC and its related entities have subsequently entered into a *Companies' Creditors Arrangement Act* proceeding in November 2013. Based on the uncertain nature of these proceedings, PNG can give no assurances as to if or when the capacity relating to the Gas Transportation Service Agreement will be utilized.

The Northeast System serves the Fort St. John and Dawson Creek area through connections with the Spectra Energy pipeline system at several locations. The Northeast System also connects with a pipeline owned by Canadian Natural Resources Ltd. in two locations to obtain supply for the Fort St. John area, and with a producer's pipeline to serve the Dawson Creek area and with a Canadian Natural Resources Ltd. gas supply pipeline to serve the Tumbler Ridge area. The entire Northeast System consists of approximately 247 km of transmission lines, 2,162 km of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of 120 10^3m^3 per day.

Total natural gas deliveries were 9.0 PJ in 2013 compared with 9.5 PJ in 2012. Deliveries to PNG's large industrial customer increased approximately 1 percent from 2012 to 2013, reflecting the impact of the customer's construction project to modernize its facilities. The increase in deliveries to the large industrial customer has no impact on PNG earnings due to a deferral mechanism whereby PNG either refunds or recovers the gain or loss, respectively, in margin from certain small and large industrial customers whose actual deliveries vary from the forecast used for rate setting purposes.

Deliveries to small industrial customers in 2013 decreased by approximately 7 percent compared to 2012. This was mainly due to construction delays of a transmission pipe to a new customer and lower fuel usage by a gas producer in the Northeast service area. Deliveries to residential customers in 2013 decreased by approximately 2 percent compared to 2012 mainly due to winter temperatures that were warmer than 2012. Deliveries to commercial customers also decreased in 2013 by approximately 6 percent from 2012 levels due to the warmer winter weather and decreased commercial activity in PNG's northeast service area.

The following table sets out, by customer category, PNG's gas sales and deliveries:

	2013	2012
Deliveries: (in PJ)		
Residential	3.0	3.0
Commercial	2.8	3.0
Small industrial	2.4	2.7
Large industrial	0.8	0.8
Total deliveries	9.0	9.5

	2013	2012
Customers at Year End:		
Residential	34,914	34,570
Commercial	5,269	5,256
Small industrial	55	57
Large industrial	2	2
Total customers	40,240	39,875

PNG currently has exclusive franchise agreements with the municipalities of Prince Rupert, Port Edward, Kitimat, Terrace, Smithers, Burns Lake, Houston, Fraser Lake and Vanderhoof, entitling it to supply and distribute natural gas within those municipalities. Each of the franchise agreements have a term of 21 years, expiring in 2032 (except in the cases of Port Edward, where the agreement expires on October 5, 2031, and Prince Rupert and Fraser Lake, where both agreements expire in 2015), and is renewable at the option of either party for a further term of 21 years.

PNG also has operating agreements with the municipalities of Telkwa and Fort St. James that entitle it to install and operate gas distribution facilities in those municipalities. The initial term of each of these operating agreements has expired, and PNG is operating within ten year renewal terms which expire in 2021 and 2019, respectively. Each operating agreement provides for an unlimited number of ten year renewal terms, which take effect automatically on the expiry of the preceding renewal term. If the parties cannot agree on alterations to an operating agreement for a renewal term, the BCUC may determine such alterations.

PNG(NE) has exclusive franchise agreements with the city of Fort St. John and the District of Taylor for 21-year terms, expiring in 2018 and 2033, respectively, as well as an operating agreement with the Village of Pouce Coupe which expires in 2016. PNG(NE) also has a franchise agreement with the City of Dawson Creek expiring at the end of 2014 which PNG(NE) will be renewing, per its rights under the agreement, for a further term of 21 years. PNG(NE) operates its gas distribution facilities in the Tumbler Ridge area pursuant to a certificate of public convenience and necessity issued by the BCUC. The franchise agreements with the District of Taylor and City of Fort St. John give the municipalities the right to purchase the distribution system within the municipality on expiry of the franchise agreement, at the fair market value of the assets as a going concern. The operating agreement with the Village of Pouce Coupe is renewable for a further term of 21 years at the option of either party.

Seasonality

The natural gas distribution business in northern British Columbia is seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

Delivery rates for PNG are set based on the 10-year rolling average Degree Days expected for the application period. PNG is authorized by the BCUC to maintain a Revenue Stabilization Adjustment Mechanism regulatory account to mitigate the effect on its earnings of deliveries to certain customers caused principally by volatility in weather and the impact on deliveries. Balances in the account are recovered in customer rates over a two-year period based on forecast deliveries.

2013 PNG Regulatory Overview

In November 2013, PNG and PNG(NE) filed their 2014 revenue requirements applications for all divisions. The applications sought approval to increase rates on an interim basis effective January 1, 2014 pending the BCUC's review of the applications. The BCUC approved interim rates effective January 1, 2014 at the levels set forth in the applications.

The 2014 revenue deficiency projected for the Western System is approximately $0.9 million. PNG(NE)'s Fort St. John/Dawson Creek division has a forecast revenue deficiency of about $0.4 million and PNG(NE)'s Tumbler Ridge Division has a revenue deficiency of $0.2 million. The applied for delivery charge changes compared to December 2013 delivery rates for an average residential customer in each service area are increases of 3.2 percent for the Western System, 3.7 percent for the Fort St. John/Dawson Creek division and 20.2 percent for the Tumbler Ridge division. A negotiated settlement process is expected to be conducted with respect to the 2014 revenue requirements applications in the second quarter of 2014.

PNG is currently a participant in the Generic Cost of Capital Proceeding established by the BCUC during 2012. In Stage 1 of the Proceeding, the BCUC determined that the Benchmark Utility's Common Equity ratio should be 38.5 percent and its Return on Common Equity should be 8.75 percent effective January 1, 2013. An Automated Adjustment Mechanism was also adopted until December 31, 2015. A Stage 2 process was added to this proceeding to determine other British Columbia utilities' (including PNG's) deemed capital structure and Return on Equity for rate setting purposes for 2013. PNG has proposed a 50 percent Common Equity ratio and a 1.00 percent premium over the Benchmark Return on Common Equity for its PNG West and PNG(NE) Tumbler Ridge divisions and a 45 percent Common Equity ratio and 0.75 percent premium over the Benchmark Return on Common Equity for its PNG(NE) Fort St. John/Dawson Creek division. A decision is expected in the first half of 2014.

Inuvik Gas and Ikhil Joint Venture

Inuvik Gas is a corporation equally owned by AltaGas, the Inuvialuit Petroleum Corporation, and ATCO Midstream NWT Ltd. and the Ikhil Joint Venture ownership is comprised of AltaGas (33.3335 percent), Inuvialuit Petroleum Corporation (33.3335 percent) and ATCO Midstream NWT Ltd. (33.333 percent). The Ikhil Joint Venture owns and operates natural gas reserves, a processing facility and a 47 km pipeline that delivers natural gas to Inuvik Gas and the Northwest Territories Power Corporation.

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

At the end of 2013 Inuvik Gas provided service to 930 residential and commercial customers, the same number as in 2012.

SEMCO

SEMCO is a regulated public utility headquartered in Port Huron, Michigan. SEMCO Energy's gas utility business consists of natural gas distribution operations in Michigan and Alaska and the CINGSA Storage Facility.

SEMCO GAS

In Michigan, SEMCO Gas distributes natural gas to approximately 300,000 customers located in both southern Michigan and Michigan's Upper Peninsula, approximately 91 percent of which are residential. The remaining customers include power plants, food production facilities, furniture manufacturers and other industrial customers.

The average number of customers at SEMCO Gas has increased by an average of approximately 0.5 percent annually during the past three years (with an increase of 0.7 percent in 2013). While there may occasionally be variations in this pattern, average per customer annual gas consumption in Michigan over the longer-term has been decreasing because, among other things, new homes and appliances are typically more energy efficient than older homes and appliances. In addition, incentives to install energy efficient appliances and equipment and employ other conservation and energy-saving measures and techniques appear to have prompted customers to reduce their gas consumption.

SEMCO Gas pursues opportunities to develop service areas that are not currently served with natural gas. Expansion opportunities that currently exist represent relatively minor asset growth, but SEMCO Gas remains committed to its strategy of pursuing expansion projects that meet management's target return on investment.

SEMCO Gas' capital expenditures for the years ended December 31, 2013 and 2012 are shown in the following table:

(US$ millions)	**2013**	**2012[(1)]**
New business	7.6	5.4
System betterment and gas supply	28.2	3.8
General plant	2.6	0.5
Total	38.4	9.7

Note:

(1) AltaGas acquired SEMCO on August 30, 2012.

Operations

The SEMCO Gas natural gas transmission and delivery system in Michigan includes approximately 151 miles of gas transmission pipelines and 5,997 miles of gas distribution mains. The pipelines and mains are located throughout the southern half of Michigan's Lower Peninsula (including in and around the cities of Albion, Battle Creek, Holland, Niles, Port Huron and Three Rivers) and also in the central, eastern and western areas of Michigan's Upper Peninsula.

The following table sets out, by customer category, SEMCO Gas' sales and deliveries:

	2013	**2012 (1)**
Deliveries: (Mmcf)		
Residential	25,355	20,905
Commercial	12,391	9,951
Transport	18,190	16,735
Gas Customer Choice[(2)]	4,110	3,087
Total deliveries	60,046	50,678

	2013	**2012 (1)**
Customers at Year End:		
Residential	252,209	251,353
Commercial	22,322	21,954
Transport	256	255
Gas Customer Choice[(2)]	18,477	16,539
Total customers	293,264	290,101

Notes:

(1) AltaGas acquired SEMCO on August 30, 2012.

(2) In Michigan, the MPSC has a program known as the Gas Customer Choice Program, under which gas sales customers may choose to purchase natural gas from third-party suppliers, while SEMCO Gas continues to charge these customers applicable distribution charges and customer fees, plus a balancing fee.

Seasonality

The natural gas distribution business in Michigan is seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

Delivery rates for SEMCO Gas are set based on the 15-year rolling average Degree Days expected for the period. Temperature fluctuations impact the operating results of SEMCO Gas.

	2013				**2012 (1)**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	2,496	206	984	3,324	2,216	198	799	2,609
Degree Days - normal	2,242	163	845	3,181	2,274	159	875	3,231

Note:

(1) AltaGas acquired SEMCO on August 30, 2012.

2013 SEMCO GAS Regulatory Overview

The rates charged to customers in SEMCO Gas' service territories regulated by the MPSC include an MPSC-approved gas cost recovery ("GCR") pricing mechanism. The GCR pricing mechanisms is designed so that, in the absence of any disallowances, SEMCO Gas' cost of gas purchased is passed through to SEMCO Gas' customers on a dollar-for-dollar basis and, therefore, SEMCO Gas does not realize or recognize any income or loss on the gas commodity charge portion of rates charged to customers.

SEMCO Gas filed a depreciation study with the MPSC in December 2011, using 2010 data. On September 25, 2012, the MPSC issued an order approving new depreciation rates in SEMCO Gas' depreciation case. The new rates reflect a US$0.6 million reduction to depreciation rates compared to the previous rates and were reflected in SEMCO Gas' financial statements effective on January 1, 2013. The new depreciation rates are to be effective in distribution rates when new base rates are established in SEMCO Gas' next base rate case. SEMCO Gas is required to file a new depreciation case with the MPSC by September 25, 2017.

In January 2011, the MPSC approved a settlement increasing the base rates of SEMCO Gas an estimated US$8.1 million on a normalized annual basis and an authorized return on equity of 10.35 percent and an overall rate of return of 7.19 percent, effective January 2011 (the "Settlement"). As part of the Settlement, SEMCO Gas initiated a Main Replacement Program (the "MRP") during 2011. Under the MRP, for the period from 2011 through May 2013, SEMCO Gas maintained its current main renewal program and, in addition, spent at least an average of US$4.4 million a year to replace an additional thirteen miles of main and related structures and equipment annually, with a carrying cost rate of 11.66 percent on those additional expenditures. SEMCO Gas began imposing the MRP surcharge in June 2012, and the surcharge was expected to generate approximately US$1.5 million in additional annual revenue on a normalized annual basis.

In December 2012, SEMCO Gas filed an application with the MPSC seeking to amend the MRP effective in 2013. SEMCO Gas proposed to double the amount spent annually on the MRP from US$4.4 million to US$8.8 million; to double the miles of main replaced from 13 miles to 26 miles; to include vintage plastic main as eligible main, and to increase the MRP surcharge to recover the incremental capital costs associated with the MRP. On May 29, 2013, the MPSC issued an order approving SEMCO Gas' application. Revised surcharges, expected to generate approximately US$1.0 million in additional revenue on a normalized annual basis, are effective for the period June 1, 2013, through May 30, 2017.

An investigation into a 2004 house fire in SEMCO Gas' Michigan service territory revealed that a service riser valve malfunctioned when it was actuated by the customer, resulting in an uncontrolled flow of gas. The gas ignited, and the resulting fire caused damage to the customer's residence. During the following years, other riser valve failures have occurred without any associated property damage or personal injuries. In response, SEMCO Gas has initiated a program to replace these defective valves (the "Valve Replacement Program").

There were approximately 51,000 valves of this design in the SEMCO Gas system. SEMCO Gas has replaced approximately 41,800 of these valves as of December 31, 2013, under the Valve Replacement Program. As of December 31, 2013, SEMCO Gas has incurred approximately US$3.5 million of valve replacement costs. SEMCO Gas expects to incur an additional $0.9 million of such costs by December 31, 2014, the date by which SEMCO Gas expects to complete the Valve Replacement Program.

As part of the Settlement, the MPSC also authorized SEMCO Gas to defer the costs associated with replacing these defective service valves under the Valve Replacement Program. Recovery of the deferred amounts is not guaranteed. Rather, recovery of any amounts, including carrying charges, from actions taken by SEMCO Gas to address the valve issue and all associated expenditures will be subject to MPSC review in its next base rate case.

ENSTAR

In Alaska, ENSTAR distributes natural gas to approximately 136,000 customers in the metropolitan Anchorage area and surrounding Cook Inlet area, approximately 91 percent of which are residential. The remaining gas sales customers include hospitals, universities and government buildings. ENSTAR also provides gas transportation service to power plants and a liquefied natural gas plant. ENSTAR's service area encompasses over 57 percent of the population of Alaska.

The average number of customers at ENSTAR has increased by an average of approximately 1.0 percent annually during the past three years (with an increase of 1.2 percent in 2013). While there may occasionally be variations in this pattern, average per customer annual gas consumption in Alaska over the longer-term has been decreasing because, among other things, new homes and appliances are typically more energy efficient than older homes and appliances. In addition, incentives to install energy efficient appliances and equipment and employ other conservation and energy-saving measures and techniques appear to have prompted customers to reduce their gas consumption.

ENSTAR's capital expenditures for the years ended December 31, 2013 and 2012 are shown in the following table:

(US$ millions)	**2013**	**2012(1)**
New business	12.6	4.7
System betterment and gas supply	7.8	0.1
General plant	2.3	1.1
Total	22.7	5.9

Note:

(1) AltaGas acquired SEMCO on August 30, 2012.

Operations

ENSTAR's natural gas delivery system (including SEMCO's Alaska Pipeline Company) includes approximately 425 miles of gas transmission pipelines and 2,891 miles of gas distribution mains. ENSTAR's pipelines and mains are located in Anchorage and the Cook Inlet area of Alaska.

Historically, ENSTAR has had access to significant natural gas supplies in Cook Inlet, which is within or adjacent to its service territory. ENSTAR's distribution system, including the Alaska Pipeline Company transmission-level pipeline system, is not linked to major interstate and intrastate pipelines and thus does not have access to natural gas supplies elsewhere in Alaska, Canada, or the Lower 48 states. As a result, ENSTAR must procure its natural gas supplies under gas supply agreements from producers in and near the Cook Inlet area. Natural gas production in Cook Inlet has decreased significantly in recent years. Due in part to this decline in production, ENSTAR historically found it difficult to obtain firm gas supply contracts. In 2013, in part due to the entry of new gas producers in Cook Inlet, ENSTAR obtained firm gas supply contracts through the first quarter of 2018.

In order to better address the seasonal deliverability demands of ENSTAR's customers, ENSTAR developed the CINGSA Storage Facility. The CINGSA Storage Facility, a critical deliverability resource for ENSTAR customers, was completed in 2012 and customer withdrawals began on November 9, 2012.

The State of Alaska continues to investigate opportunities to bring natural gas via pipeline or LNG from the North Slope to south central Alaska. ENSTAR is engaged with the State of Alaska's efforts to assess the possibility of meeting its customers' gas supply needs through these means. ENSTAR has historically viewed LNG exports as a driver of Cook Inlet area gas exploration and development activity. The LNG export plant in Kenai, Alaska (the "LNG Plant") has also historically supported the local deliverability of natural gas, since gas intended for liquefaction and eventual export has been diverted from time to time for local use, including during cold weather periods. The LNG Plant recently applied for a new export license to export approximately 40 Bcf from Cook Inlet. In light of the relative stability of its gas supply, ENSTAR does not oppose this application.

The following table sets out, by customer category, ENSTAR's sales and deliveries:

	2013	2012 (1)
Deliveries: (in Mmcf)		
Residential	19,034	20,982
Commercial	13,333	14,375
Transport	19,109	19,102
Total deliveries	51,476	54,459

	2013	2012 (1)
Customers at Year End:		
Residential	123,941	121,927
Commercial	12,402	12,367
Transport	16	14
Total customers	136,359	134,308

Note:

(1) AltaGas acquired SEMCO on August 30, 2012.

Seasonality

The natural gas distribution business in Alaska is seasonal, as the majority of natural gas demand occurs during the winter heating season that extends from November to March. Accordingly, annualized individual quarterly revenues and earnings are not indicative of annual results.

Delivery rates for ENSTAR are set based on the 10-year rolling average Degree Days expected for the period. Temperature fluctuations impact the operating results of ENSTAR.

	2013				**2012 (1)**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	3,518	845	1,848	3,680	3,936	1,039	1,688	4,431
Degree Days - normal	3,565	903	1,638	3,884	3,565	903	1,638	3,884

Note:

(1) AltaGas acquired SEMCO on August 30, 2012.

2013 ENSTAR Regulatory Overview

The rates charged to customers in ENSTAR's service territories has an RCA-approved gas cost adjustment pricing mechanism. The gas cost adjustment pricing mechanisms is designed so that, in the absence of any disallowances, ENSTAR's cost of gas purchased is passed through to ENSTAR's customers on a dollar-for-dollar basis and, therefore, ENSTAR does not realize or recognize any income or loss on the gas commodity charge portion of rates charged to customers.

In June 2009, ENSTAR and Alaska Pipeline Company filed a base rate and rate design case with the RCA. A settlement of this matter was negotiated among all of the parties and accepted by the RCA in August 2010. With the new base rates, ENSTAR's base rate revenue was increased by US$7.0 million on a normalized annual basis. ENSTAR is obligated to submit another base rate and rate design filing to the RCA on or before August 1, 2014, based on data from a test year ended December 31, 2013.

CINGSA

SEMCO Energy, through a subsidiary, holds a 65 percent interest in CINGSA. CINGSA was formed to construct, own and operate the CINGSA Storage Facility. Natural gas is injected into the storage facility during each summer and withdrawn as needed for use each winter.

Four utilities, including ENSTAR (78 percent), Chugach Electric Association (16 percent), Anchorage Municipal Light & Power (5 percent) and Alaska Electric and Energy Cooperative (1 percent), have entered into 20 year contracts for 100 percent of the initial storage capacity of CINGSA.

CINGSA commenced "free-flow" injections into its storage facility on April 1, 2012. In-service operations for the CINGSA Storage Facility began on November 9, 2012, when construction of the surface facilities was completed and withdrawal capability became available to storage customers. The CINGSA Storage Facility is actively being used by ENSTAR and CINGSA's three electric utility customers in the Cook Inlet area of Alaska.

CINGSA's capital expenditures for the years ended December 31, 2013 and 2012 are shown in the following table:

(US$ millions)	**2013(1)**	**2012(1)(2)**
New business	6.6	11.8
Total	6.6	11.8

Notes:

(1) Numbers reflect SEMCO Energy's 65 percent interest.
(2) AltaGas acquired SEMCO on August 30, 2012.

2013 CINGSA Regulatory Overview

As stipulated in the CINGSA certification proceedings accepted by the RCA, in February 2012 CINGSA filed an update to its proposed rates for service from the CINGSA Storage Facility to reflect revised estimates of construction costs. The calculation of rate base, a levelized revenue requirement and initial rates were adjusted to reflect an updated projected capital cost of US$161.4 million for the CINGSA Storage Facility. In March 2012, the RCA approved CINGSA's adjustments to its initial rates with an effective date of April 1, 2012. In 2014, CINGSA is required to further update its rates to reflect actual construction and operating costs. CINGSA is also required to file a base rate case with the RCA in mid-2017 based upon data from a test year ending December 31, 2016.

On September 18, 2013, CINGSA received a $15.0 million gas storage facility tax credit ("Tax Credit") from the State of Alaska for the benefit of its firm storage service ("FSS") Customers. CINGSA will derive no direct or indirect benefit from the Tax Credit. The Tax Credit, and any interest accrued thereon, will be distributed to the FSS Customers provided that CINGSA does not cease commercial operations prior to January 1, 2022. If CINGSA ceases commercial operations, it must refund a proportional share of the Tax Credit to the State of Alaska.

Following receipt of the Tax Credit, CINGSA deposited the funds in a separate interest-bearing account. CINGSA will act as a custodian of the Tax Credit and any interest earned for the benefit of CINGSA's FSS Customers. On an annual basis through the end of 2021, CINGSA will disburse to the FSS Customers 1/10th of the amount of the Tax Credit not subject to refund to the State and interest earned. The RCA has approved the disbursement methodology. The funds related to 2012 were disbursed to CINGSA's Customers in December 2013 and the funds related to 2013 were disbursed in February 2014.

OTHER SEMCO

SEMCO Energy's other businesses primarily include operations and investments in propane distribution, intrastate natural gas pipelines, and a natural gas storage facility which accounted for approximately one percent of SEMCO Energy's 2013 consolidated operating revenues. SEMCO Energy's propane distribution operation typically sells approximately 2.6 million gallons of propane annually to retail customers in Michigan's Upper Peninsula and northeast Wisconsin. At the end of 2013, SEMCO Energy's propane distribution served 5,827 residential and commercial customers compared with 5,888 residential and commercial customers in 2012. SEMCO Energy’s pipeline and storage operations own and operate intrastate natural gas transmission pipelines and a non-controlling interest in a gas storage facility in Michigan.

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 businesses are reported in the Corporate segment. The Corporate segment decreased net revenue with a loss of $14.2 million for the year ended December 31, 2013.

AltaGas holds shares of Alterra Power Corp., formerly Magma Energy Corporation. Magma completed a merger with Plutonic Power Corporation and subsequently changed its name to Alterra Power Corp. on May 18, 2011. The initial Magma shares were 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 six percent of the common shares of Alterra Power Corp. on December 31, 2013.

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.

Description of Capital Structure

The authorized capital of AltaGas consists of an unlimited number of Common Shares and such number of Preferred Shares issuable in series at any time as have aggregate voting rights either directly or on conversion or exchange that in the aggregate represent less than 50 percent of the voting rights attaching to the then issued and outstanding Common Shares. The summary below of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares is subject to, and qualified by reference to, AltaGas' articles and by-laws.

Common Shares

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of AltaGas, to receive dividends if, as and when declared by the Board of Directors and to receive the remaining property and assets of AltaGas upon its dissolution or winding-up, subject to the rights of shares having priority over the Common Shares.

On April 4, 2013, AltaGas closed a public offering of 11,615,000 Common Shares at a price of $34.90 per Common Share for aggregate gross proceeds of approximately $405 million.

On October 1, 2013, AltaGas issued 2,801,905 Common Shares as part of the consideration for the acquisition of Petrogas Energy Corp. See *"General Development of AltaGas' Business – Historical Development – Acquisition of Petrogas"*.

Preferred Shares

The Board of Directors may divide any unissued Preferred Shares into series and fix the number of shares in each series and the designation, rights, privileges, restrictions and conditions thereof. The Preferred Shares of each series will rank on a parity with Preferred Shares of every other series with respect to accumulated dividends and return of capital and entitled to a preference over the Common Shares and over any other shares of AltaGas ranking junior to the Preferred Shares with respect to the priority in the payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding-up of AltaGas, whether voluntary or involuntary.

The rights, privileges, restrictions and conditions attaching to the Preferred Shares as a class may be repealed, altered, modified, amended or amplified or otherwise varied only with the sanction of the holders of the Preferred Shares given in such manner as may then be required by law, subject to a minimum requirement that such approval be given by resolution in writing executed by all holders of Preferred Shares entitled to vote on that resolution or passed by the affirmative vote of at least 66⅔ percent of the votes cast at a meeting of holders of Preferred Shares duly called for such purpose.

For the specific rights, privileges, restrictions and conditions attaching to the Series A Shares and the Series B Shares, reference should be had to the prospectus supplement of AltaGas dated August 11, 2010 relating to the issue of the Series A Shares. For the specific rights, privileges, restrictions and conditions attaching to the Series C Shares and the Series D shares, reference should be had to the prospectus supplement of AltaGas dated May 30, 2012 relating to the issue of the Series C Shares. For the specific rights, privileges, restrictions and conditions attaching to the Series E Shares and Series F Shares, reference should be had to the prospectus supplement of AltaGas dated December 6, 2013 relating to the issue of the Series E Shares. Each such prospectus supplement has been filed with, and may be retrieved from, SEDAR at www.sedar.com.

Employees

At December 31, 2013 there were 1,571 individuals employed in AltaGas' businesses.

Gas	301
Power	79
Utilities	1,012
Corporate	179
Total	**1,571**

Directors and Officers

As at March 1, 2014 the directors and executive officers of AltaGas Ltd., as a group, owned beneficially, directly or indirectly, or exercised control or direction over 2,980,308 of the outstanding Common Shares, or approximately 2.4 percent of the outstanding Common Shares. As at March 1, 2014 certain of the directors and officers also had been granted options to acquire an aggregate of 2,890,550 Common 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 March 1, 2014, 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 (6) Calgary, Alberta, Canada Chairman and Chief Executive Officer	Mr. Cornhill is a founding member of AltaGas Services, predecessor to AltaGas. He has served as Chairman and Chief Executive Officer since AltaGas Services' inception on April 1, 1994 and was appointed as a Director of the General Partner on May 1, 2004. Prior to forming AltaGas Services, 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
Catherine M. Best (1) Calgary, Alberta, Canada Director	Ms. Best is an independent businesswoman. Ms. Best was the Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region from 2000 to March 2009. Before joining the Calgary Health Region she was with Ernst & Young in Calgary for nineteen years, the last ten as Corporate Audit Partner.	November 30, 2011
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. 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

Name of Director, Municipality of Residence and Position	Principal Occupation During the Past Five Years	Director Since
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
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. (now GLJ Petroleum Consultants 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][4] 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
Myron F. Kanik [1][2] Qualicum Beach, British Columbia, 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 [1][5] 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 1998 until 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.	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 revoked 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 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. Robert B. Hodgins, a director of AltaGas, was a director of Skope Energy Inc. ("Skope") from December 15, 2010 to February 19, 2013. On November 27, 2012, Skope was granted protection from its creditors by the Court of Queen's Bench of Alberta pursuant to the *Companies' Creditors Arrangement Act*. A plan of compromise and arrangement was approved by the required majority of Skope's creditors on February 15, 2013, and was sanctioned by the Court of Queen's Bench of Alberta on February 19, 2013.
(5) Mr. M. Neil McCrank, a director of AltaGas, was, from July 17, 2008 to April 5, 2011, a director of MegaWest Energy Corp. ("MegaWest"), a reporting issuer in the provinces of Alberta and British Columbia. On September 7, 2010, a cease trade order was issued by the ASC against MegaWest for failure to file its annual audited financial statements, management's discussion and analysis and certification of annual filings for the year ended April 30, 2010. On September 8, 2010, the BCSC issued a cease trade order against MegaWest for failure to file its annual audited financial statements and management's discussion and analysis for the year ended April 30, 2010, and its annual information form for the years

ended April 30, 2009 and 2010. Such filings were completed by MegaWest in September and October of 2010 and revocation orders were issued by the ASC and BCSC on October 22, 2010.

(6) Mr. Cornhill is not considered to be an independent director as he is an executive officer of AltaGas.

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, 2013, are identified below:

Director	Audit Committee	Governance Committee	HRC Committee	EOH&S Committee
David W. Cornhill				✓
Catherine M. Best	✓			
Allan L. Edgeworth	✓			Chair
Hugh A. Fergusson	✓		✓	
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.
Dennis A. Dawson Calgary, Alberta, Canada Vice President, General Counsel and Corporate Secretary	Vice President General Counsel and Corporate Secretary of AltaGas since 1998.
David M. Harris Calgary, Alberta, Canada Chief Operating Officer	Chief Operating Officer of AltaGas from August 2013. President Gas and Power of AltaGas from December 2012 to August 2013. President Power of AltaGas from May 2011 to December 2012. Vice President Major Projects Power of AltaGas from October 2010 to May 2011. General Manager Forrest Kerr of AltaGas from June 2010 to October 2010. Prior thereto President and Chief Operating Officer of MW Power Corp. from March 2009 to June 2010; Senior Vice President of Engineering, Procurement and Construction of NRG Energy Inc. from November 2006 to March 2009.
John E. Lowe Calgary, Alberta, Canada Executive Vice President Corporate Development	Executive Vice President Corporate Development of AltaGas from December 2012. President AltaGas Utility Group Inc. from October 2011 to December 2012. Partner with the law firm of Burnet, Duckworth and Palmer LLP from September 2005 to October 2011.

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
Deborah S. Stein DeWinton, Alberta, Canada Senior Vice President Finance and Chief Financial Officer	Senior Vice President Finance and Chief Financial Officer of AltaGas from May 2011. Vice President Finance and Chief Financial Officer of AltaGas from July 2010 to May 2011. Vice President Finance and Chief Financial Officer of the General Partner from January 2008 to June 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.
Kent E. Stout Airdrie, Alberta, Canada Vice President Corporate Resources	Vice President Corporate Resources of AltaGas since 2002. Director Human Resources from 1999 to 2002.
David R. Wright Calgary, Alberta, Canada Executive Vice President	Executive Vice President of AltaGas from December 2012. Executive Vice President Strategy and Corporate Development of AltaGas from July 2010 to December 2012. 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

Audit Committee Mandate

See attached Schedule A for the Audit Committee Mandate.

Composition of the Audit Committee

The Committee is currently comprised of Catherine M. Best, Allan L. Edgeworth, 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

Catherine M. Best was the Executive Vice-President, Risk Management and Chief Financial Officer of the Calgary Health Region from 2000 to March 2009. Before joining the Calgary Health Region she was with Ernst & Young LLP in Calgary for nineteen years, the last ten as Corporate Audit Partner.

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 Inc. where he held various positions including Vice President of Pipeline Operations, Senior Vice President of Regulatory Affairs and President Pipeline Division.

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.

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, during 2013 and 2012 were as follows:

Category of External Auditor Service Fee	2013	2012
Audit Fees	$1,757,769	$1,007,707
Audit-Related Fees(1)	$34,163	$15,740
Tax Fees(2)	$52,919	$--
All Other Fees(3)	$339,518	$425,239
TOTAL	$2,184,369	$1,448,686

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 Canadian Public Accountability Board ("CPAB") registration costs.

(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 advice.

(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 services required for AltaGas' public finance activities.

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.

General Economic Conditions

AltaGas' operations are affected by the condition and overall strength of the economies of Canada and the U.S. During economic downturns, the demand for the products and services that AltaGas provides and the supply of or demand for power, natural gas and NGLs may be adversely affected. The occurrence of periods of poor economic conditions or low or negative economic growth could have an adverse impact on AltaGas' results.

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 construction, 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 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 or its affiliates 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.

Underinsured and Uninsured Losses

AltaGas maintains insurance coverage at all times in respect of certain potential liabilities and the accidental loss of value of certain of its assets, in amounts and with such insurers as it considers appropriate, taking into account relevant factors. It is anticipated that such insurance coverage will be maintained, however there can be no assurance that AltaGas will be able to obtain or maintain adequate coverage in the future or at rates it considers reasonable. Further, there can be no assurance that available insurance will cover all losses or liabilities that might arise in the conduct of AltaGas' business. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by AltaGas, or a claim that falls within a significant self-insured retention could have a material adverse effect on AltaGas' business or its results.

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. AltaGas' businesses are subject to the risks normally associated with the operation and development of natural gas, NGL and power systems and facilities, including mechanical failure, transportation problems, 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, store, transport, deliver or distribute natural gas or NGLs or generate or deliver power.

AltaGas does not operate certain facilities, including the power plant from which power is generated under the Sundance 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.

Volume Throughput

AltaGas' businesses process, transport and store natural gas, ethane, NGLs and other commodities. Throughput within the business 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. 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.

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.

Natural Gas Supply Risk

Adequate supplies of natural gas may not be available to satisfy committed obligations as a result of economic events, natural occurrences and/or failure of a counterparty to perform under a gas purchase contract.

Biomass Supply Risk

Adequate supplies of biomass fuel may not be available to satisfy committed obligations as a result of economic events, natural occurrences and/or failure of a counterparty to perform under a supply contract.

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. Power generated from both Bear Mountain and Busch Ranch is not currently exposed to power price volatility as the power generated is sold at a fixed price for 25 years, with escalation factors of 50 percent of CPI and 2 percent, respectively. In addition, power sold from the McNair run-of-river power generation facility is not exposed to power price volatility as the power generated is sold at a fixed price for 20 years escalated at 50 percent of CPI. Power sold from the Grayling Generating Station in Michigan and the Craven County wood biomass power facility in North Carolina is not exposed to market prices and is sold under long-term PPAs. Gas-fired generation capacity at Blythe Energy is operating under a long-term PPA with SCE and serves the CAISO market. Due to the structure of the long-term PPA, the majority of the facility's revenues are derived from being available to produce and not the actual production, therefore providing stable cash flows.

Interest Rates

AltaGas is exposed to interest rate fluctuations on variable rate debt. Interest rates are influenced by Canadian, U.S. and global economic conditions beyond AltaGas' control.

Regulatory

AltaGas' businesses are subject to extensive and complex laws and regulations 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, PNG, Heritage Gas and SEMCO Energy operate in regulated marketplaces where regulatory approval is required for the regulated returns that provide for recovery of costs and a return on capital and may limit the ability to make and implement independent management decisions, including setting rates charged to customers and issuing debt.

Regulations and laws are subject to ongoing policy initiatives, and AltaGas cannot predict the future course of regulations or legislation and their respective ultimate effects on AltaGas or Petrogas. Such changes could materially impact AltaGas' business, financial position and results of operations.

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.

Foreign Exchange Risk

AltaGas is exposed to foreign exchange risk through its investments in the United States. Changes in the Canada/United States exchange rate could impact the earnings of AltaGas, the value of the United States investments and the cash generated from the United States businesses.

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.

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 Blythe Energy Center, the Younger Extraction Plant and some employees of AUI, PNG and SEMCO Energy are members of a labour union. Labour disruptions could restrict the ability of the Blythe Energy Center to generate power, the ability of the Younger Extraction Plant to process natural gas and produce NGLs or could affect AUI's, PNG's or SEMCO Energy'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, development of natural gas projects 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 operation or development of facilities for gathering and processing, LNG, LPG, natural gas distribution, 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, defects in construction, 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 hydroelectric power projects 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' wind power projects 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 utilities 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 Utilities 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 and to attract additional talented personnel to the organization. Access to a sustained labour market from which to attract the required expertise, knowledge and experience is a critical factor to AltaGas' success. Costs associated with attracting and retaining key personnel could adversely affect AltaGas' business operations and financial results.

Information and Control Systems

Unethical, illegal or improper access to or use of AltaGas' information and control systems could cause AltaGas' critical systems or sensitive information to be compromised. Information and control systems by their nature are complex and interdependent. Compromise of the systems or failure of the systems could adversely affect AltaGas' business operations and financial results.

Technical Systems and Processes Incidents

Failure of key technical systems and processes to effectively support information requirements and business processes may lead to AltaGas' inability to effectively and efficiently measure, record, access, analyze and accurately report key data. This could result in increased costs and missed business opportunities.

Service Interruptions

Service interruption incidents that may arise through unexpected major power disruptions to facilities or pipeline systems, third-party negligence or unavailability of critical replacement parts could cause AltaGas to be unable to safely and effectively operate its assets. This could adversely affect AltaGas' business operations and financial results.

Cook Inlet Gas Supply

ENSTAR's gas distribution system, including the Alaska Pipeline Company pipeline system, is not linked to major interstate and intrastate pipelines or natural gas supplies in the lower 48 states of the United States or in Canada. As a result, ENSTAR procures natural gas supplies under long-term RCA-approved contracts from producers in and near the Cook Inlet area. Declining production from the Cook Inlet gas fields may result in potential deliverability problems in ENSTAR's service area. There is ongoing exploration for natural gas in the Cook Inlet area, including producers that have supply contracts with ENSTAR. Activity also continues with respect to the possible construction of a natural gas pipeline that would extend from Alaska's North Slope, through central Alaska and Canada, to the lower 48 states of the United States. There are no assurances, however, with respect to these gas supply-related matters, including when such pipelines might be constructed and put in service or whether natural gas supplies transported by such pipelines would be available to ENSTAR's customers and secured by ENSTAR on terms and conditions that would be acceptable to the RCA.

ENVIRONMENTAL REGULATION

AltaGas faces uncertainties related to future environmental laws and regulations affecting its business and operations. Existing environmental laws and regulations may be revised or interpreted more strictly, and new laws or regulations may be adopted or become applicable to AltaGas, which may result in increased compliance costs or additional operating restrictions, each of which could reduce AltaGas' earnings and adversely affect AltaGas' business.

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 places 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, state, territorial and federal legislation requires that facility sites and pipelines be abandoned and reclaimed to the satisfaction of provincial or state 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 assesses its environmental liabilities on an ongoing basis and remediates and reclaims sites according to the jurisdiction's requirements when they are now longer needed.

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.

Climate Change

In particular, changes in laws and regulations relating to greenhouse gas emissions could require AltaGas, in addition to complying with greenhouse gas monitoring and reporting requirements applicable to its operations, to (i) comply with stricter emissions standards for internal combustion engines used to run compressors on AltaGas' natural gas transmission and distribution systems; (ii) take additional steps to control transmission and distribution system leaks; (iii) install new emission controls on AltaGas equipment or replace such equipment; and/or (iv) reduce AltaGas' greenhouse gas emissions or, depending on the requirements enacted, acquire emissions allowances or pay taxes on the greenhouse gases emitted in connection with its operations. AltaGas' business could also be indirectly impacted by greenhouse gas laws and regulations that affect its customers or suppliers, to the extent such changes result in reductions in the use of natural gas by its customers or limit the operations of, or increase the costs of goods and services acquired from AltaGas suppliers, such as pipelines and natural gas producers.

It is uncertain at the present time what form greenhouse gas laws or regulations may take if eventually enacted, and whether and in what ways AltaGas, its customers, and others may be affected by any new requirements or obligations relating to greenhouse gas emissions. It is reasonably possible, however, that future legislative, regulatory or judicial actions could result in increased costs or changes in AltaGas' operations and/or could affect the demand for natural gas, which could reduce AltaGas' earnings and adversely impact AltaGas' business.

International Climate Change Agreements

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 and is in line with the reduction commitment made by the U.S. However, the Copenhagen Accord does not contain any binding commitments to reduce CO_2 emissions, nor does it include any discussion of compliance mechanisms.

Canadian Federal GHG Regulations

The Canadian federal government has started to address emissions within specific sectors of the economy. On September 5, 2012, the Environment Minister proposed the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*. The performance standard element of the proposed regulations would come into effect on July 1, 2015. In addition, units would be required to begin reporting two years in advance of when they reach their end of useful life date or, in the case of new units, in the first year of operation. Regulated entities would then be subject to enforcement and compliance requirements and penalties as specified under the *Canadian Environmental Protection Act, 1999*.

Canadian Provincial GHG Regulations

On March 8, 2007 the Alberta government introduced the *Climate and Emissions Management Amendment Act* and the *Specified Gas Emitters Regulation*. The legislation 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 greater than 100,000 tonnes of carbon dioxide equivalent per annum. .

Large emitters with eight or more years of commercial operation must achieve a net emission intensity of 88 percent relative to the baseline emissions intensity that was established for the facility. Annual emissions intensity reduction targets are phased in for newer facilities.

Compliance options include: (i) making facility enhancements to reduce greenhouse gas emissions, (ii) purchasing Alberta-based offsets or emission performance credits, or (iii) contributing to the Alberta government's Climate Change and Emissions Management Fund that will invest in transformative technologies that will reduce greenhouse gas emissions in the province. Owners of facilities that do not achieve the necessary reduction through operating improvements, emission offsets or emission performance credits, must pay into the Climate Change and Emissions Management Fund. In late 2011, the *Specified Gas Emitters Regulation* was amended so that the contribution cost is no longer specified at the $15/tonne level. Instead, the contribution cost will be set by the Order of the Minister.

AltaGas has completed an assessment of its Canadian facilities and assets and has identified that both the Harmattan Complex and the Sundance B PPA will be considered large emitters under Alberta's *Specified Gas Emitters Regulation* since each facility exceeded 100,000 tonnes of greenhouse gas emissions in 2013.

The Sundance B Plant is a large emitter and TransAlta, as the facility owner, must ensure that the 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' expected share of the cost of compliance for 2013 is approximately $6.0 million.

On January 10, 2010 the government of British Columbia enacted the *Greenhouse Gas Reduction Act (Cap and Trade)*. Draft regulations have been posted by the British Columbia Climate Action Secretariat, but have not yet been finalized.

The province also introduced a carbon tax of $10/tonne in 2008 and increased it to the maximum of $30/tonne in 2012.

Canadian Provincial Mercury Regulations

On February 6, 2006 the Alberta government passed the *Mercury Emissions from Coal-Fired Power Plants Regulation*, under the Alberta *Environmental Protection and Enhancement Act*. 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 selected activated carbon injection technology to meet the 70 percent targeted reduction in mercury emissions by January 1, 2011. Operation of the mercury control equipment commenced in 2010 and according to TransAlta, has remained operational since.

U.S. GHG Regulations

There have been several attempts in the past three years to implement greenhouse gas legislation in the United States, none of which have been passed in either the Senate or the House of Representatives.

Manufactured Gas Plants

SEMCO Energy's operations and businesses are subject to laws and regulations that relate to the environment and health and safety, including those that impose liability for the costs of investigation and remediation of contamination resulting from, and for damages to natural resources due to, past spills, on- and off-site waste disposal and other releases of hazardous materials or regulated substances. In particular, under applicable environmental requirements, SEMCO Energy may be responsible for the investigation and remediation of environmental conditions at currently owned or leased sites, as well as formerly owned, leased, operated or used sites. SEMCO Energy may be subject to associated liabilities, including liabilities resulting from lawsuits alleging property damage or personal injury brought by private litigants related to the operation of SEMCO Energy's facilities or the land on which such facilities are located, regardless of whether SEMCO Energy leases or owns the facility, and regardless of whether such environmental conditions were created by SEMCO Energy or by a prior owner or tenant, or by a third party or a neighbouring facility whose operations may have affected SEMCO Energy's facility or land. Prior to the construction of major interstate natural gas pipelines, gas for heating and other uses was manufactured from processes involving coal, coke or oil. Residual by-products of these processes may have caused environmental conditions that require investigation and remediation. SEMCO Energy owns three sites in Michigan where such MGPs were located and recently disposed of four other properties where such MGPs were located. Even though SEMCO Energy never operated MGPs at four of the sites, and did so at one site for only a brief period of time, SEMCO Energy is subject to United States local, state and federal laws and regulations that require, among other things, the investigation and, if necessary, the remediation of contamination associated with these sites, irrespective of fault, legality of initial activity, or ownership, and which may impose liability for damage to natural resources.

Given the nature of the past operations conducted by SEMCO Energy and others at SEMCO Energy's properties, particularly those involving former MGP sites, there can be no assurance that all potential instances of soil or groundwater contamination have been identified, even for those properties where environmental site assessments or other investigations have been or will be conducted. Changes in existing laws or policies or their enforcement, future spills or accidents or the discovery of currently unknown contamination may give rise to environmental liabilities which may be material.

Compliance with the requirements and terms and conditions of the environmental licences, permits and other approvals that are required for the operation of SEMCO's business may cause SEMCO to incur substantial capital costs and operating expenses and may impose restrictions or limitations on the operation of SEMCO's business, all of which could be substantial. Environmental, health and safety regulations may also require SEMCO to install pollution control equipment, modify its operations or perform other corrective actions at its facilities.

DIVIDENDS

AltaGas pays cash dividends on the Common 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 Series A Shares, Series C Shares and Series E Shares 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.

The table shows the cash dividends paid by AltaGas on Common Shares in 2011, 2012 and 2013.The table also summarizes the cash dividends paid by AltaGas on the Series A Shares, issued in August 2010, in 2011, 2012 and 2013 and the cash dividends paid by AltaGas on the Series C Shares, issued in June 2012, in 2012 and 2013. The Series E Shares were issued in December 2013. The first dividend payment on Series E shares will be in Q1 2014.

Dollars per share	**2013**	**2012**	**2011**
Common Shares	1.4850	1.3950	1.3250
Series A Shares	1.2500	1.2500	1.2500
Series C Shares	US1.100	US$0.6223	-

DIVIDEND REINVESTMENT PLAN

AltaGas has adopted a Dividend Reinvestment and Optional Share Purchase Plan for holders of Common Shares.

The Plan, as may be amended from time to time, provides eligible holders of Common Shares with the opportunity to reinvest the cash dividends paid by AltaGas on their Common Shares towards the purchase of new Common Shares at a 5 percent discount to the Average Market Price (as defined below) of the Common Shares on the applicable dividend payment date (the dividend reinvestment component of the Plan). The Plan also provides shareholders who are enrolled in the dividend reinvestment component of the Plan with the opportunity to purchase new Common 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 Common 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 Common Shares on the TSX for the trading days on which at least one board lot of Common 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 Common Share subdivisions, Common Share consolidations, certain rights offerings and certain dividends).

No brokerage commissions will be payable in connection with the purchase of Common 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 Common 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 Common Shares traded by month from January to December 2013 as reported by the TSX:

Month	High	Low	Volume Traded
January	36.66	33.00	4,147,981
February	35.98	34.35	4,821,000
March	36.79	34.60	7,463,907
April	37.62	34.61	6,985,529
May	40.80	37.17	13,910,127
June	39.36	34.67	9,289,378
July	38.06	35.32	5,921,657
August	37.89	34.85	4,912,958
September	36.99	34.80	4,562,250
October	39.14	35.11	6,128,853
November	39.86	37.85	4,423,882
December	40.91	38.03	4,812,494

The Corporation's Series A Shares are traded on the TSX under the symbol ALA.PR.A. The following table sets forth the monthly price range and volume traded for AltaGas' Series A Shares from January to December 2013 as reported by the TSX:

Month	High	Low	Volume Traded
January	26.68	25.90	266,671
February	26.93	26.15	189,654
March	26.95	26.26	126,816
April	26.75	25.87	124,366
May	26.80	26.00	117,186
June	26.25	24.80	130,025
July	25.80	25.11	112,175
August	25.76	24.53	169,144
September	25.60	24.74	137,230
October	25.73	25.35	130,961
November	26.24	25.26	101,133
December	25.89	24.63	218,387

The Corporation's Series C Shares are traded on the TSX under the symbol ALA.PR.U. The following table sets forth the monthly price range and volume traded for AltaGas' Series C Shares from January to December 2013 as reported by the TSX:

Month	High	Low	Volume Traded
January	25.63	25.25	225,860
February	25.99	25.30	132,279
March	26.13	25.02	268,360
April	25.79	25.13	242,651
May	26.54	25.60	155,505
June	26.20	25.10	223,149
July	25.54	25.12	182,810
August	25.31	24.44	253,932
September	25.24	24.69	157,392
October	25.01	24.70	225,277
November	25.39	24.76	142,854
December	25.42	24.78	225,877

The Corporation's Series E Shares began trading on the TSX on December 13, 2013 under the symbol ALA.PR.E. The following table sets forth the monthly price range and volume traded for AltaGas' Series E Shares for the period of December 13 – 31, 2013 as reported by the TSX:

Month	High	Low	Volume Traded
December 13 - 31	25.45	24.69	943,659

SELECTED CONSOLIDATED FINANCIAL INFORMATION

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

Year ended and as at December 31[1] *($ millions unless otherwise indicated)*	**2013**	**2012**	**2011** **(Restated)**
Revenue			
Gas	1,019.83	844.0	1,085.0
Power	00.4	216.1	168.0
Utilities	894.4	437.6	161.0
Corporate	(9.2)	22.1	(9.0)
Intersegment Eliminations	(162.5)	(70.2)	(125.1)
	2,042.9	1,449.7	1,280.0
Net revenue			
Gas	368.9	322.0	337.9
Power	177.1	109.0	113.6
Utilities	434.7	212.7	81.9
Corporate	(14.2)	22.6	(18.4)
Intersegment Elimination	(6.3)	(2.0)	(1.9)
	960.2	664.4	513.1
EBITDA	538.9	319.3	257.2

Year ended and as at December 31[1] *($ millions unless otherwise indicated)*	**2013**	**2012**	**2011** **(Restated)**
Net income	181.5	101.8	82.7
- per share (basic)	1.56	1.07	0.98
Funds from operations	400.3	254.6	213.3
Total assets	7,281.3	5,932.4	3,556.2
Total debt	3,246.1	2,702.3	1,337.1

Notes:

(1) 2011 values have been restated from prior years to reflect the adoption of US GAAP.
(2) Amounts may not add due to rounding.

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 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. AltaGas' Preferred Shares continue to have 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.

AltaGas provides an annual fee to both S&P and DBRS for credit rating services.

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:

- The $1.4 billion Extendible Revolving Term Credit Facility Credit Agreement. This is an unsecured extendible revolving credit facility with Royal Bank of Canada, Canadian Imperial Bank of Commerce, Toronto Dominion Bank, Bank of Montreal, Bank of Nova Scotia, Alberta Treasury Branches, National Bank of Canada, Canadian Western Bank, Hong Kong and Shanghai Banking Corporation, Bank of America, N.A., Canada Branch and JP Morgan Chase Bank maturing on December 15, 2017. 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;
- The Trust Indenture between AltaGas and Computershare Trust Company of Canada dated July 1, 2010, as supplemented, related to the issuance and sale of medium term note debentures pursuant to AltaGas' medium term note program; and
- The Share Purchase Agreement dated October 23, 2013 between SAM Holdings Ltd., Petrogas, the AltaGas Idemitsu LP, AltaGas and Idemitsu Kosan Co.,Ltd. related to the acquisition by the AltaGas Idemitsu LP of a 41⅔ percent interest in Petrogas.

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

AltaGas is not aware of any material interest, direct or indirect, of any director or officer of AltaGas, 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 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' Management Information Circular, which is expected to be filed on or about March 10, 2014 in connection with the Annual General Meeting of shareholders to be held May 1, 2014.

Additional financial information is contained in AltaGas' consolidated financial statements for the year ended December 31, 2013 and management's discussion and analysis contained in the 2013 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 Common Shares and the Preferred Shares is Computershare Investor Services Inc., 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, 2013.

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 Management's 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.

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