ALTAGAS LTD.

Annual Information Form

For the year ended December 31, 2014

Dated: March 20, 2015

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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 AltaGas' role as project manager of the Douglas Channel LNG Project, the expected commissioning date for the McLymont Creek facility, the potential for the Blythe Energy Center to serve both the CAISO-operated California market and the DSW market after July 31, 2020, the expected in-service date of a third cogeneration facility at Harmattan and the potential for a three-fold increase in AltaGas' current generating capacity in California over the medium and long-term. In addition, forward-looking statements are set forth under the following sub-headings:

- "*AltaGas' Vision and Objective*", including expectations regarding the abundant supply of natural gas in North America and the increasing global demand for clean energy is expected to continue to provide opportunities for sustained growth across all of AltaGas' business segments;

- "*AltaGas' Strategy*", including the potential to provide clean and affordable energy to customers in Asia, expectations for the optimization of existing assets and through the development of new infrastructure, including energy export opportunities; and expectations that AltaGas is in a position to deliver higher netbacks to producers and improve cost-efficiencies;

- "*AltaGas' Strategy – Investing in and Operating Energy Infrastructure*", including expectations for the increased use of natural gas providing opportunities for AltaGas to invest in and optimize assets; expectations as to AltaGas' ability to provide producers access to the highest value markets; expectations related to AltaGas' access to Asian markets; expectations for the economic growth and increased demand for clean sources of power to reduce greenhouse gas emissions requiring significant development in gas-fired and renewable generation; and the expectation for growth in the Utilities segment as a result of expansion of existing distribution systems, acquisition of new franchises, fuel switching and investment in existing distribution systems;

- "*AltaGas*' *Strategy Execution*", including with respect to opportunities to expand the Blythe Energy Center; the expected commissioning date for the McLymont Creek facility; the expected in-service date of a third cogeneration facility at Harmattan; and the expectation that AltaGas is well-positioned to fund its growth capital and to take advantage of growth opportunities as they arise.

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 Harmattan; the intention to pursue LPG and LNG export opportunities through AIJVLP; the construction, operation and expected in service date of the Townsend gas processing facility; expectations for further processing infrastructure build-out opportunities in northeast British Columbia; expectations for the construction of a network of LNG facilities through northern B.C.; and the expected capacity, components and completion date of the pilot LNG facility in Dawson Creek;

  - *"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 date of the McLymont Creek facility and the expected cash flows to be derived therefrom; expected cash flow derived from the Volcano Creek facility and the Forrest Kerr facility; and the potential for Blythe II to double the existing generation capacity in California;

- *"Business of the Corporation"* under the following sub-headings:
    - *"Gas Business – Extraction"*, including in respect of the impact of commodity prices or operating costs on NGL extraction; and expectations for extraction rights being retained by extraction facility owners;
    - *"Gas Business – Field Gathering and Processing and Transmission"*, 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; AltaGas' competitiveness in the midstream marketplace; expectations regarding the Porcupine Hills pipeline; and the expectation that Nova Chemicals will exercise its option to purchase EDS and JFP effective March 15, 2017;
    - *"Gas Business – Energy Services"*, including expectations regarding the completion of the Alton natural gas storage project;
    - *"Gas Business – Energy Export"*, including in respect of expectations of the opportunities export infrastructure creates to unlock the value of the WCSB's natural gas reserves; the expectations related to AltaGas' unique position to provide producers with a competitive service; the expectations related to AltaGas' ability to access Asian markets; the expectations for AltaGas to provide multiple outlets for producers to deliver their natural gas and NGL products to the highest value markets; and expectations as to AltaGas' role as project manager of the Douglas Channel LNG Project.
    - *"Power Business"*, including in respect of expectations for growth through renewable energy projects and gas-fired generation opportunities, including the Blythe Energy Center; expectations regarding developing activities that triple AltaGas' generation capacity in the vicinity of the Blythe Energy Center; expectations regarding the timing of completion and in-service date of Cogeneration III; the expectations for the future organic growth opportunities via repowering of the three western U.S. gas-fired power assets acquired by AltaGas on January 8, 2015; 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 intentions of BMWLP in respect of green attributes and RECs; the expected commissioning date of the McLymont Creek Facility; expectations regarding the cost characteristics of the Sundance B plant; the contribution of the Northwest Projects to British Columbia's goal of energy self-sufficiency and in an environmentally and socially responsible manner; the ability to generate further growth for the power infrastructure business with its clean energy portfolio; the supply-demand balance for power in Alberta; and the timing of development and intentions with respect to the development of AltaGas' clean power development projects in Canada and the United States;
    - *"Utilities Business"*, including expectations regarding AUI's annual growth of service sites; AUI's PBR formula and the capital tracker; 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 for CNG loading and unloading infrastructure to provide access to natural gas for customers not connected through the traditional pipeline distribution infrastructure; 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 Heritage Gas' ability to serve Antigonish County and the regulatory implications thereof; expectations of alternatives available to Heritage Gas as a result of the expected decline in natural gas supply from the Sable Offshore Energy Project; expectations regarding the in-service date of Atlantic Bridge Project; expectations of the benefits to be provided to Heritage Gas as a result of the ruling issued by the NSUARB on February 20, 2014; expectations by Heritage Gas on the issuance of a ruling by the NSUARB in response to its application submitted in December of 2014; expectations by Heritage Gas regarding the completion of the Alton gas storage project; expectations for the environmental and consultation process for, and the timing of a final investment decision on, PLP; expectations regarding PNG(NE)'s 2015 revenue requirements application for its Fort St. John/Dawson Creek divisions, expectations regarding PNG's letter application for PNG West and PNG(NE) TR requesting that the 2014 rates remain in effect for 2015 and any potential increases or decreases in its cost of service be addressed through a deferral account to be amortized during 2016, expectations regarding a negotiated settlement process with respect to the 2015 revenue requirements application; expectations regarding the revenue generated by SEMCO Gas' MRP surcharge; expectations on the completion of the regulatory proceedings related to the MRP contested rate case; expectations related to the annual average capital spending by SEMCO Gas on the MRP and revenues collected by the customer over a five year period; 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 base rate and rate design case filed by

ENSTAR and Alaska Pipeline Company with the RCA; expectations regarding the pursuit of sales of the native gas found in CINGSA's storage well; expectations regarding the working capacity of the CINGSA Storage Facility; and expectations regarding CINGSA filings with the RCA regarding rates;

- *"Risk Factors"* under the following sub-headings:
    - *"Capital Markets"*, including in relation to AltaGas' belief that it has sufficient funds to funds its projected capital expenditures;
    - *"Cook Inlet Gas Supply"*, including the potential for gas supplies as a result of exploration for natural gas in the Cook Inlet area; and in relation to the possible construction of a natural gas pipeline extending from Alaska's North Slope to the lower 48 states of the United States; and
- *"Additional Information"* in respect of the anticipated filing date of AltaGas' Management Information Circular and the date of AltaGas' annual general meeting of shareholders.

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;

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

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

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

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

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

"**AUH(US)**" means AltaGas Utility Holdings (U.S.) Inc.;

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

"**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;

"**BC Hydro**" means British Columbia Hydro and Power Authority;

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

"**BDS**" means Butane Delivery System;

"**Blythe**" means Blythe Energy Inc.;

"**Blythe Energy Center**" means the gas-fired 507 MW Blythe Energy Center located near Blythe, California, owned by AltaGas' indirect wholly-owned subsidiary Blythe;

"**Blythe II**" means the fully permitted and shovel-ready site for the development of an approximately 500 MW power generation expansion, located directly adjacent to the Blythe Energy Center;

"**Blythe III**" means the 76 acres of land for the development of an approximately 500 MW power generation expansion, located north of the Blythe Energy Center and directly adjacent to Blythe II;

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

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

"**C&I**" means commercial and industrial;

"**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;

"**CCAA**" means the *Companies' Creditors Arrangement Act*, R.S.C. 1985, c. C 36, 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;

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

"**Cogeneration III**" means the expansion of the cogeneration fleet at Harmattan from 30 MW to 45 MW;

"**Cold Lake Pipeline Expansion**" means the expansion project of AltaGas' gas transmission system to deliver natural gas to two heavy oil projects near Cold Lake, Alberta;

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

"**Consortium**" means the group consisting of AIJVLP, EXMAR and EDFT formed to develop the Douglas Channel LNG project;

"**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;

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

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

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

"**DBRS**" means DBRS Limited and its successors;

"**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 AltaGas Decker Energy Inc., formerly named Decker Energy International, Inc.;

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

"**EDFT**" means EDF Trading Limited;

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

"**EEEP**" means the Edmonton ethane extraction plant and related facilities, AltaGas' interest being owned by its indirect wholly-owned subsidiary AltaGas Extraction and Transmission Limited Partnership;

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

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

"**EXMAR**" means EXMAR NV;

"**Ferndale**" means the storage, distribution and export facility for bulk shipments of propane, butane and iso-butane located on the coast near Ferndale, Washington, and owned by a subsidiary of Petrogas;

"**Forrest Kerr**" means the 195 MW run-of-river hydroelectric facility, one of the three run-of-river hydroelectric projects in northwest British Columbia that are the Northwest Projects;

"**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, owned by AltaGas' indirect wholly-owned subsidiary AltaGas Processing Partnership;

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

"**Harmattan**" means the combined Harmattan gas processing facility and extraction plant and associated facilities, owned by AltaGas' indirect wholly-owned subsidiary Harmattan Gas Processing Limited Partnership;

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

"**Idemitsu**" means Idemitsu Kosan Co.,Ltd.;

"**Ikhil Joint Venture**" means the joint venture between AltaGas' subsidiary Utility Group Facilities Inc., 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 kilometer;

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

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

"**m^3**" means a cubic meter 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**" 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;

"**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;

"**MTN**" means medium term note;

"**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;

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

"**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, being Forrest Kerr, McLymont Creek and Volcano Creek, owned by AltaGas' subsidiary Coast Mountain Hydro Limited Partnership;

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

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

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

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

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

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

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

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

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

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

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

"**Pool**" means the scheme operated by the Alberta Independent System Operator for (i) exchanges of electric energy, and (ii) financial settlement for the exchange of electric energy;

"**PPA**" means power purchase arrangement with respect to TransAlta's Sundance B facility, and means power purchase agreement in all other contexts;

"**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, Series F Shares, Series G Shares and Series H Shares;

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

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

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

"**RECs**" means Renewable Energy Credits;

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

"**REPA**" means renewable energy purchase agreement;

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

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

"**SEDAR**" means System for Electronic Document Analysis and Retrieval, at www.sedar.com;

"**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;

"**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 (US dollar);

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

"**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;

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

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

"**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 Generation Partnership;

"**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 dollar**" or "**US$**" means currency in the form of United States dollars;

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

"**Volcano Creek**" means the 16 MW run-of-river hydroelectric facility, one of the three run-of-river hydroelectric projects in northwest British Columbia that are the Northwest Projects;

"**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, AltaGas' interest being owned by its indirect wholly-owned subsidiary AltaGas Extraction and Transmission Limited Partnership.

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 meters	28.174
cubic meters	cubic feet	35.494
Bbls	cubic meters	0.159
cubic meters	Bbls	6.290
tonnes	long tons	0.984
feet	meters	0.305

To Convert From	To	Multiply By
meters	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 is a corporation amalgamated pursuant to the CBCA on July 1, 2010. AltaGas' head, principal and registered office is located at 1700, 355 – 4th Avenue SW, Calgary, Alberta T2P 0J1. AltaGas is a public company trading on the TSX under the symbol "ALA".

At December 31, 2014 AltaGas had 133,941,749 outstanding Common Shares, 8,000,000 outstanding Series A Shares, 8,000,000 outstanding Series C Shares, 8,000,000 outstanding Series E Shares and 8,000,000 outstanding Series G Shares.

On July 3, 2014, AltaGas closed a public offering of 8,000,000 Series G Shares at a price of $25.00 per Series G Share for aggregate gross proceeds of approximately $200 million.

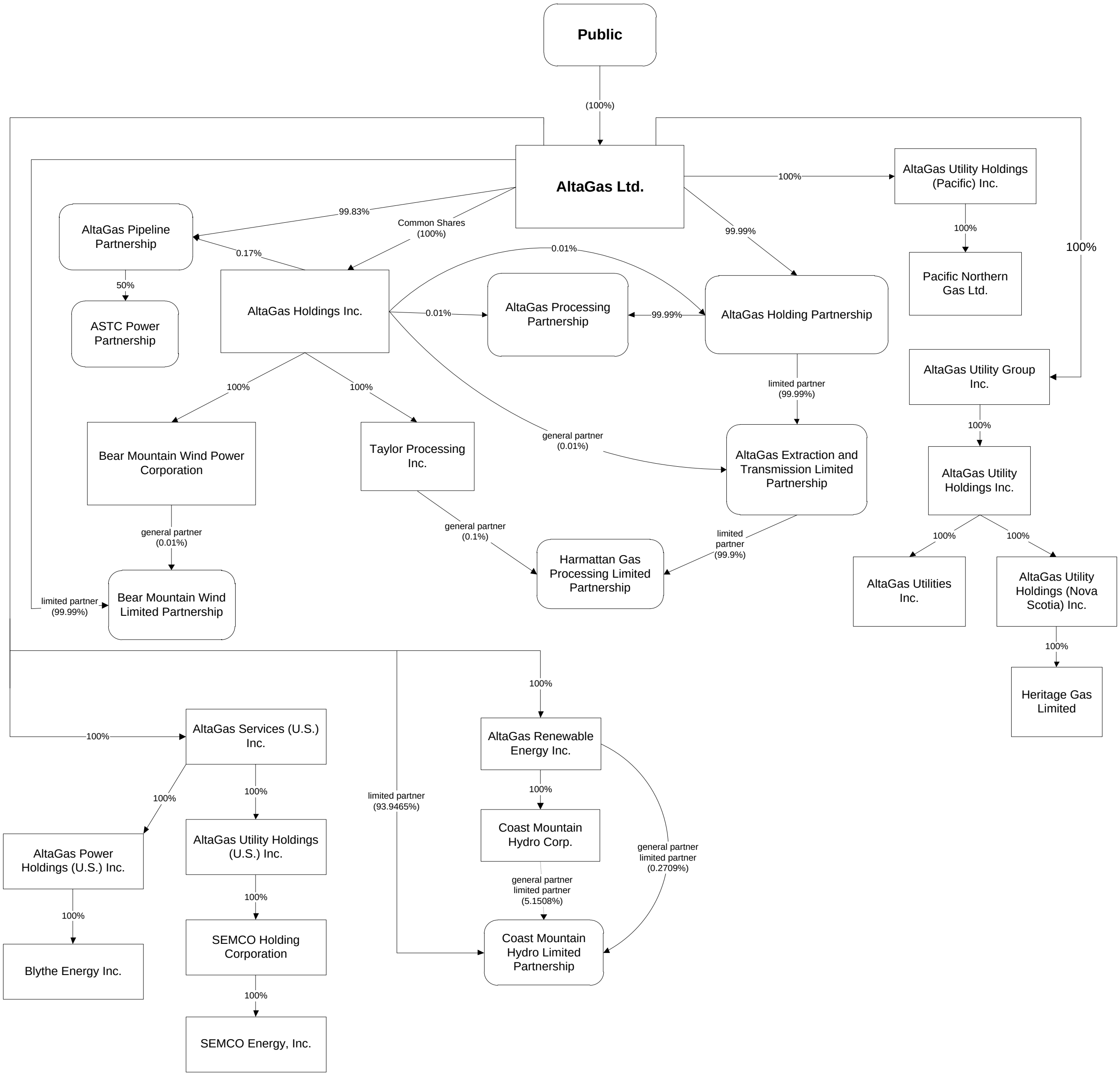
On August 28, 2014, AltaGas closed a public offering of 9,027,500 Common Shares at a price of $51.00 per Common Share for total gross proceeds of approximately $460 million.

See *"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 certain of AltaGas' subsidiaries as at December 31, 2014. The assets and revenues of excluded subsidiaries individually did not exceed 10 percent, and 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, 2014.



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 and Asia. AltaGas' business strategy is underpinned by strong growth in natural gas supply and the growing demand for clean energy. AltaGas executes its strategy through three business segments: Gas, which includes natural gas processing, transportation, storage, and natural gas marketing; Power, which includes power generation assets, power purchase agreements for power supply, and sale of power to C&I customers; and Utilities, which include regulated natural gas distribution utilities across North America and a regulated natural gas storage utility in the United States. AltaGas has an enterprise value of over $9 billion. With the physical and economic links along the energy value chain, primarily from wellhead 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 business segments, and growing through the acquisition and development of energy infrastructure, including infrastructure required to support the export of LNG and LPG from North America.

Gas

AltaGas' Gas segment serves producers in the WCSB and transacts more than 2 Bcf/d of natural gas. It includes natural gas gathering and processing, NGL extraction and fractionation, transmission, storage and natural gas marketing. The Gas segment also includes the Corporation's 50 percent investment in AIJVLP which in turn owns the Corporation's one-third interest in 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 NGL. The transmission pipelines deliver natural gas and NGL 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.

AIJVLP is pursuing energy export opportunities, including long-term supply and sales arrangements to meet the growing demand for LNG and LPG in Asia. Idemitsu, AltaGas' partner in AIJVLP, is a global leader in the supply of energy, petroleum, lubricants and petrochemical products and services to Japan. Petrogas is a leading North American integrated midstream company with an extensive logistics network consisting of over 1,500 rail cars and 24 rail and truck terminals, which provides key infrastructure, supply logistics and marketing expertise required to pursue LPG export opportunities. Together, AltaGas, Idemitsu and Petrogas bring key infrastructure assets and marketing expertise along with energy supply and access to markets in Asia to pursue LPG export opportunities.

Through AIJVLP, AltaGas and Idemitsu formed the Consortium, which includes EDFT and EXMAR, to support the plan of arrangement under CCAA proceedings for the Douglas Channel LNG project. The Douglas Channel LNG project is a proposed barge-based LNG export facility on the west bank of the Douglas Channel in Kitimat, British Columbia with a nameplate capacity of 0.55 million tonnes per annum. On January 28, 2015, the Consortium announced that it had obtained full ownership and control of the Douglas Channel LNG project as a result of the statutory plan of arrangement completed under the CCAA proceedings. The Consortium has executed long-term lease agreements with the Haisla Nation regarding land and water tenure and with PNG for long-term pipeline capacity to supply gas to the project. AltaGas will act as the project manager of the Douglas Channel LNG project. The Consortium is targeting a final investment decision by the end of 2015 and commercial operation in 2018.

Power

As at December 31, 2014, the Power segment includes 1,285 MW of power generation capacity from gas-fired, coal-fired, wind, biomass and run-of-river assets, along with an additional 81 MW of assets under construction. On January 8, 2015 AltaGas completed the acquisition of three western U.S. gas-fired power assets with a total generation capacity of 164 MW. As a result, AltaGas entered 2015 with 1,449 MW of total power generation capacity.

In 2014, the 195 MW Forrest Kerr and 16 MW Volcano Creek facilities were commissioned. The 66 MW McLymont Creek facility will be the third and final Northwest Project to come online, with commissioning expected in mid-2015. The 277 MW Northwest Projects are contracted with 60-year EPAs with BC Hydro that are fully indexed to the CPI.

Impact Benefit Agreements are in place for the Northwest Projects, ensuring a cooperative and mutually beneficial relationship between the Tahltan First Nation and AltaGas.

AltaGas owns Blythe, which owns Blythe Energy Center, a 507 MW natural gas-fired power plant, associated major spare parts and a related 230 kV 67-mile electric transmission line in southern California. Blythe 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 markets. In 2014, AltaGas acquired Blythe II. Also in 2014, AltaGas acquired Blythe III. The development of both projects could potentially more than triple AltaGas' current generating capacity in California over the medium and long-term.

AltaGas is also expanding its cogeneration fleet at Harmattan from 30 MW to 45 MW. AltaGas is in the final stages of construction of Cogeneration III, which is being constructed to meet the increased power demand at Harmattan and to increase sales to the Alberta power market. Cogeneration III is expected to be in service in the first half of 2015.

AltaGas owns 50 percent of the Sundance B PPAs, giving it the rights to 353 MW of power output and ancillary services from coal-fired base-load generation until December 31, 2020.

AltaGas owns 117 MW of wind power generation capacity, as well as 35 MW of biomass generation capacity, from which all power generation is sold via long-term contracts.

Utilities

The Utilities segment is comprised of natural gas distribution utilities that serve more than 560,000 customers in Canada and the United States. The Utilities segment in Canada is composed of AUI in Alberta, PNG in British Columbia, Heritage Gas in Nova Scotia, as well as a one-third equity interest in Inuvik Gas in the Northwest Territories. The Utilities segment in the United States is comprised of SEMCO Gas in Michigan, ENSTAR in Alaska and a 65 percent interest in CINGSA, also 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 diversified 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 utility-like returns and long-life cash flows. Diversification increases the stability of earnings and cash flows and reduces AltaGas' exposure to commodity market volatility. AltaGas' earnings are underpinned by three business segments, and within each segment there is further diversification; by customer and service type in the Gas segment, by fuel source and geography within the Power segment, and by regulatory jurisdiction in the Utilities segment. The Corporation also focuses on expanding 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 increasing global demand for clean energy will continue to provide opportunities for sustained growth across all its business segments.

ALTAGAS' STRATEGY

AltaGas' strategy is to execute opportunities created by the renaissance of natural gas in North America and the increasing global demand for clean energy by owning and operating a diversified mix of assets in gas, power and utilities. In the Gas segment, AltaGas' strategy is focused on investing in assets that process and move natural gas to key markets, including Asia, to provide a fully integrated midstream service offering to its customers across the energy value chain. AltaGas is uniquely positioned to deliver higher netbacks to producers for natural gas and NGL through its ownership interest in Petrogas and Ferndale, as well as through AltaGas' role in the Douglas Channel LNG project. The Power segment is focused on building, owning, and operating a diversified portfolio of clean energy assets that reduces the Corporation's carbon footprint and on meeting North America's demand for clean energy. In the Utilities segment, the Corporation is focused on finding innovative ways to continue to deliver clean and affordable natural gas to more customers safely and reliably.

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. AltaGas has the ability to safely deliver capital projects on time and on budget, in close partnership with First Nations and community stakeholders.

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

Investing in and Operating Energy Infrastructure

Natural gas supply and demand fundamentals and the demand for clean energy have consistently underpinned the Corporation's strategy. In recent years, the supply and demand fundamentals have been changing. Abundant supply of natural gas in North America, driven by new technology that has improved the economics of unconventional gas plays, has been positive news for North American energy consumers and has led to renewed interest in natural gas as an economically priced, clean burning fuel. As a result, the use of natural gas for power generation and household, commercial and industrial uses is expected to increase substantially, providing significant opportunities across AltaGas' Gas, Power and Utilities segments to invest in and optimize assets.

The abundant supply and relatively low natural gas prices in North America stand in sharp contrast to the higher prices in Asia. Investing in export infrastructure represents a compelling opportunity to unlock the value of western Canada's vast natural gas reserves. AltaGas is uniquely positioned to provide producers a competitive service offering across the integrated value chain, from wellhead to tidewater. Access to Asian markets provides the opportunity for attractive netbacks to producers, especially those in the vast Montney and Duvernay basins under development in northeastern British Columbia and western Alberta. Through AltaGas' ownership of the only natural gas pipeline to Kitimat and Prince Rupert (through its wholly-owned subsidiary PNG), and its investment in Petrogas, with its logistics network of rail cars, terminals and storage facilities, including Ferndale acquired in 2014, AltaGas can provide multiple outlets for producers to deliver their natural gas and NGL products to the highest value markets. In partnership with Idemitsu, AltaGas is actively pursuing multiple LNG and LPG export opportunities.

AltaGas expects that economic growth and increased demand for clean sources of power to reduce greenhouse gas emissions will require significant development in gas-fired and renewable generation. Within the Power segment, growth is planned through the completion of projects currently under construction, the expansion of existing assets, and through the development of its portfolio of clean energy generation in North America. AltaGas' strategic acquisition of the Blythe Energy Center provides significant opportunities to grow that facility to meet the growing demand for power in California and surrounding regions. See *"General Development of AltaGas' Business – Historical Development – Development of the Power Business*".

Within the Utilities segment, growth is expected through expansion of the existing distribution systems to acquire new customers, acquisition of new franchises when it is cost effective or strategic to do so, fuel switching as abundant natural gas provides a clean low-cost energy alternative and investment in existing distribution systems to ensure safe, reliable service for AltaGas' customers. There are also natural gas storage opportunities currently under development in Nova Scotia to increase reliability of supply to AltaGas' natural gas distribution customers in that area.

AltaGas is an industry leading operator of energy infrastructure serving customers since 1994. AltaGas strives to employ the best available practices and technologies for integrity management systems and maintenance and operations in order to mitigate risks to the public, employees and the environment. Cost efficiency and operating performance are the drivers for increasing value as the Corporation continues to build out its portfolio of assets. Key initiatives continue to increase proficiency in managing costs and include changes to cost tracking systems and implementing best practice procurement strategies. Superior service, safety and reliability are also integral to AltaGas' customer value proposition. AltaGas has approximately 1,700 employees building long-term relationships and sustainable benefits in the communities in which AltaGas operates.

Maintain Financial Strength and Flexibility

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

A key element of the Corporation's stable business model is mitigating its exposure to certain market price risks as well as volume risk. In addition to its diversification strategy, the Corporation has developed risk management processes that mitigate earnings volatility from commodity price risk and volume risk. AltaGas proactively hedges interest rates, foreign exchange rates and commodity price exposures. As well, the continued management of counterparty credit risk remains an ongoing priority. AltaGas mitigates the foreign exchange exposure on its United States investments by incorporating US dollar denominated capital, both debt and preferred shares, into its financing strategy.

AltaGas seeks to optimize risk and reward, ensuring that returns are commensurate with the level of risk assumed.

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

ALTAGAS' STRATEGY EXECUTION

AltaGas has successfully executed its strategy to create shareholder value and to maintain financial strength and flexibility, growing from under $3 billion in assets five years ago to total assets of over $8 billion at the end of 2014. In the last three years, the Corporation has reported 6 percent and 10 percent compound annual growth rate in earnings and dividends per share, respectively. AltaGas delivers an effective balance between yield and growth.

2014 was a significant year for AltaGas. The Corporation safely commissioned Forrest Kerr, the largest construction project in its 20-year history, on time and on budget and completed Volcano Creek two years ahead of schedule. Adding these high quality renewable generation assets, which deliver long-term stable cash flows supported by 60-year EPAs, demonstrates the successful execution of AltaGas' strategy. AltaGas continues to make good progress at McLymont Creek, which is expected to be in service in mid-2015. In addition, AltaGas optimized its power portfolio in 2014 by divesting the ownership of 25 MW of peaking capacity exposed to the merchant Alberta power market, and entered into a purchase and sale agreement for 164 MW of contracted gas-fired assets located in the western United States. The transaction closed on January 8, 2015 and increased AltaGas' presence in the U.S. and overall contracted position to further support stable cash flows. AltaGas delivered growth in its Power generation segment of 32 percent in 2014, providing over 75 percent of total generation from clean energy sources, including hydro, wind, biomass and gas-fired.

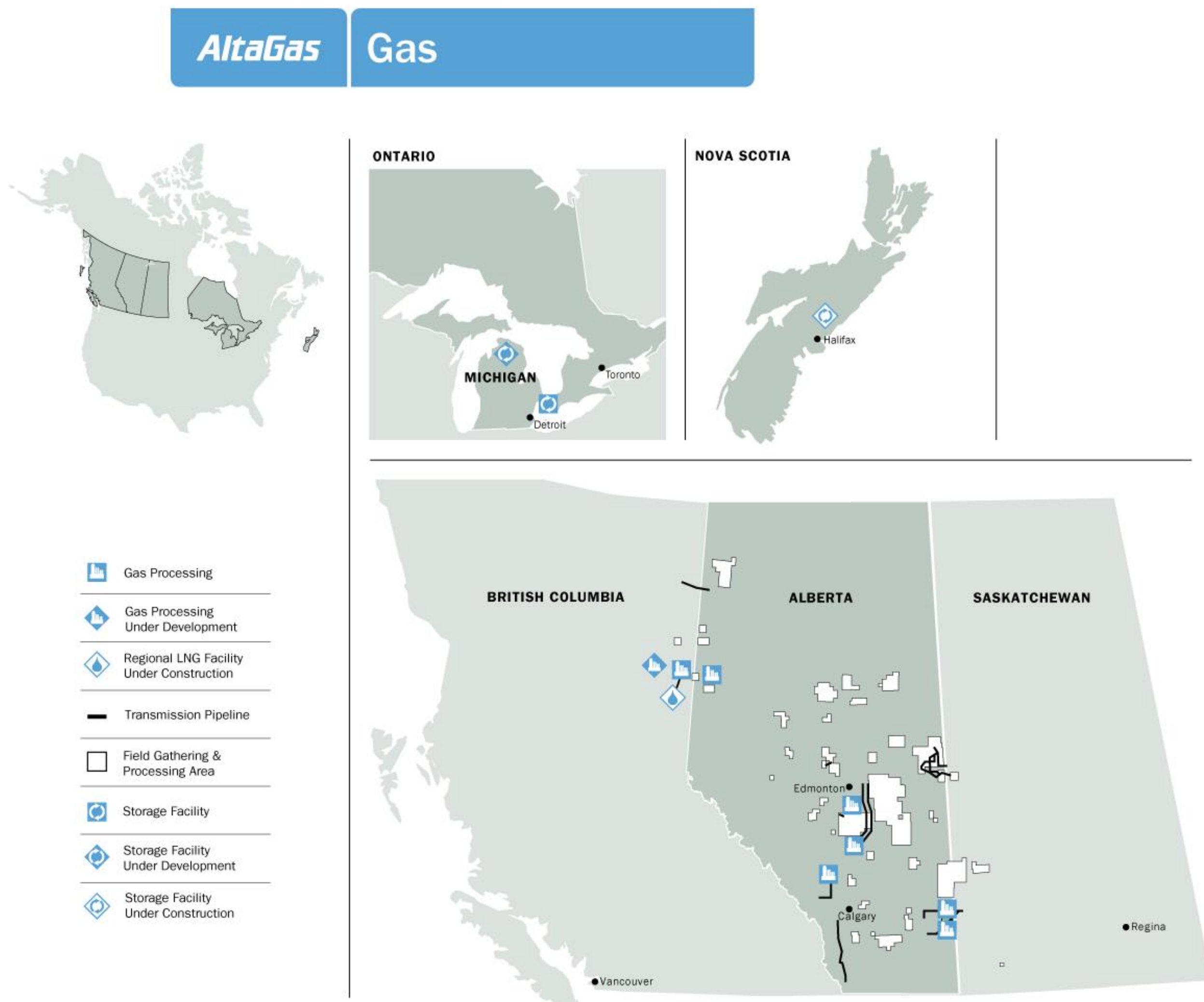
AltaGas also opened the doors to international markets in 2014 and built a competitive service offering for producers. The Corporation enhanced its logistics capabilities by increasing its investment in Petrogas in early 2014, bringing its ownership interest to one-third. Petrogas subsequently acquired Ferndale, which completed two shipments to Asia off the U.S. west coast in 2014. In addition, AltaGas made significant progress on executing its strategy to export LNG off Canada's west coast. The Douglas Channel LNG export initiative was granted creditor approval in 2014, enabling AltaGas and its partners to proceed with the project. Gaining access to Asian markets and building competencies from wellhead to tidewater has positioned AltaGas as a preferred partner for producers. This was validated by a 15-year strategic alliance with Montney producer Painted Pony Petroleum Ltd., which was executed in 2014. AltaGas has established a competitive advantage of providing an integrated service offering for producers to earn higher netbacks through the successful execution of its strategy in 2014.

In 2014, AltaGas initiated further growth in all business lines with projects such as the acquisition of the Blythe II development project and the land acquisition for Blythe III, completing commercial agreements for a 198 Mmcf/d shallow-cut gas processing facility to be known as the Townsend Facility, and beginning groundwork on AltaGas' first regional LNG facility in Dawson Creek, British Columbia. Construction of Cogeneration III is advancing and the project remains on schedule with completion expected in the first half of 2015. In fourth quarter 2014, AltaGas completed the construction of the second part of the Cold Lake Pipeline Expansion. Across the utilities, AltaGas continued to focus on customer and rate base growth by expanding its existing infrastructure through system upgrade programs and organic growth opportunities.

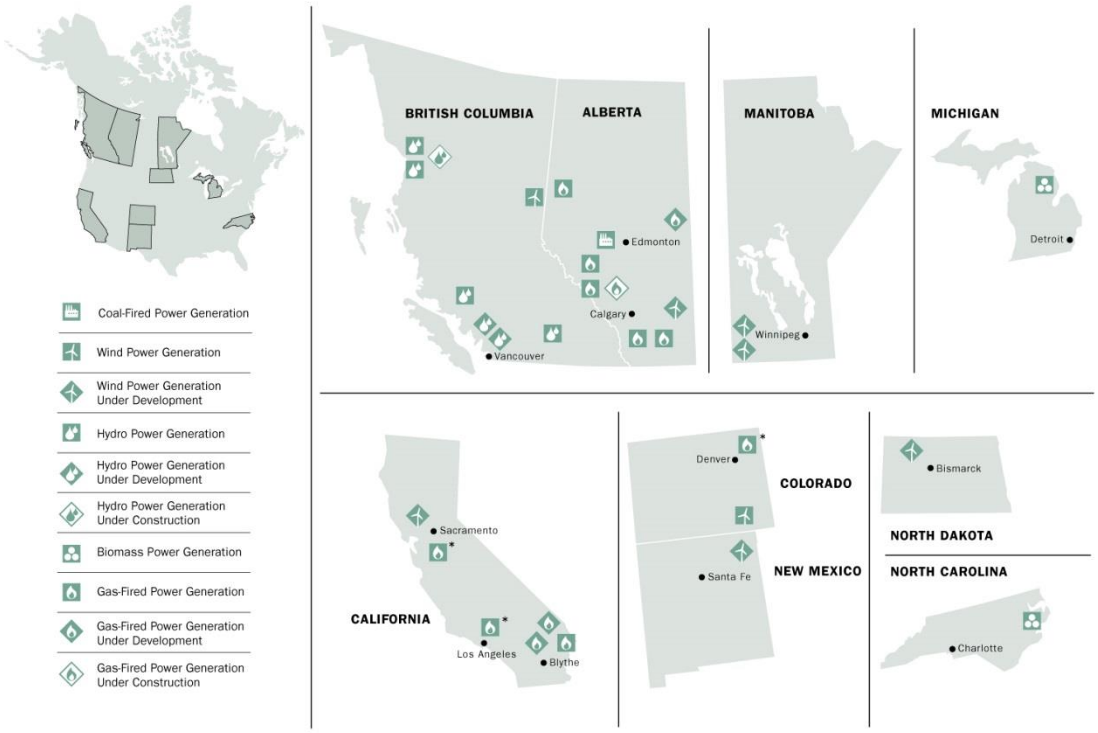
In 2014, the Corporation enhanced its financial strength and flexibility through a combination of internally-generated cash flows, the Plan, and the issuance of $1.8 billion of equity and long-term debt. The Corporation extended its debt maturity profile and lowered its cost of debt with the early redemption of $500 million of MTNs and the issuance of $1.1 billion of MTNs, including the $400 million 30-year issuance. During the year, AltaGas completed a $460 million Common Share issuance and a $200 million Preferred Share issuance, Series G Shares. AltaGas maintained sufficient liquidity and a strong balance sheet throughout the year and exited 2014 with approximately $1.7 billion of available credit facilities, cash and short-term investments of $421 million, and debt-to-total capitalization of 45 percent. AltaGas entered 2015 exceptionally well-positioned to fund its growth capital and to take advantage of growth opportunities when they arise.

In May 2014, the Board of Directors approved a 16 percent dividend increase from $1.53 per share to $1.77 per share on an annualized basis. The dividend increase reflects the success of AltaGas' asset additions across all business segments and the strength and stability of its cash flows.

ALTAGAS' GEOGRAPHIC FOOTPRINT



AltaGas Power



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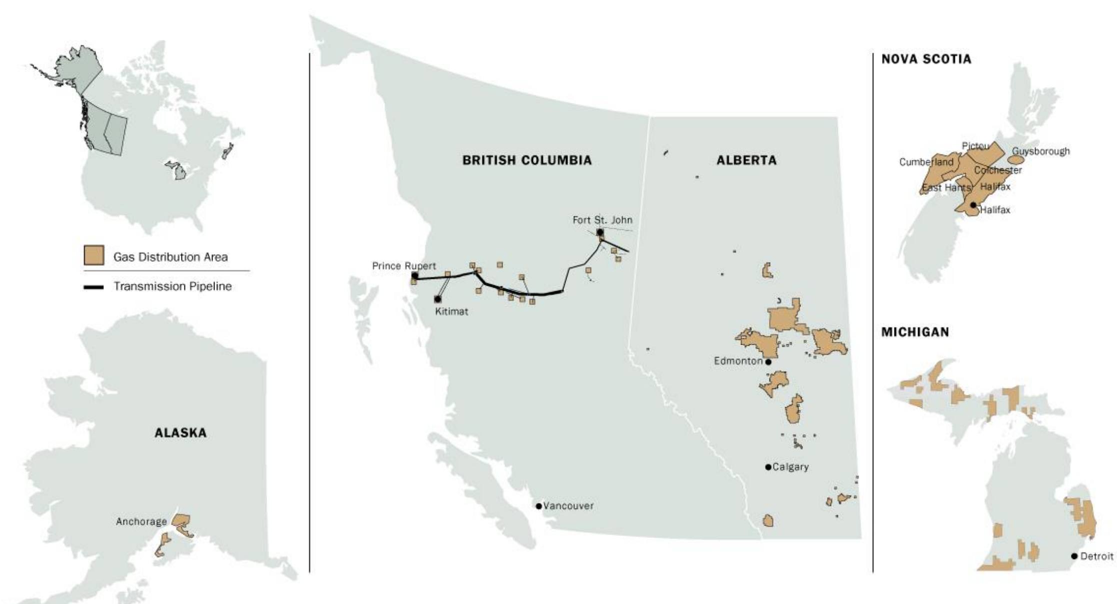


GENERAL DEVELOPMENT OF ALTAGAS' BUSINESS

HISTORICAL DEVELOPMENT

AltaGas Services 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. AltaGas Services 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 AltaGas Services 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 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 Harmattan to recover ethane and NGLs. The Co-stream Facility provides an opportunity to increase utilization of Harmattan, 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 AIJVLP. AIJVLP 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 began construction of the Cold Lake Pipeline Expansion. The first portion of the Cold Lake Pipeline Expansion was completed in fourth quarter 2013 and the second portion was completed in fourth quarter 2014. The Cold Lake Pipeline Expansion is 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 L.P., which owns the 10 Bcf Alton underground 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 L.P. pursuant to the acquisition of Landis Energy Corporation in 2010.

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

In May 2014, AltaGas signed an agreement with Petrogas to operate its newly acquired Ferndale facility, located in Washington.

In June of 2014 AltaGas and the Province of British Columbia signed a letter of intent to grow the use of LNG in the province. The letter of intent commits the Province of British Columbia and AltaGas to work towards a project development agreement to support AltaGas' plans to build a network of small LNG facilities throughout northern British Columbia. Work has since begun on the construction of a pilot facility in Dawson Creek, with expected commercial operation date to occur by the end of 2015. The facility will have initial capacity of approximately 20,000 gallons per day and will include a liquefaction plant, storage and distribution equipment.

In August 2014, AltaGas signed agreements to enter into a 15-year strategic alliance with Painted Pony Petroleum Ltd. for the development of processing infrastructure and marketing services for natural gas and NGLs. In the first phase of the strategic alliance, AltaGas will construct and operate the Townsend facility, a 198 Mmcf/d shallow-cut gas processing facility in northeast British Columbia's Montney resource play. Construction of the Townsend facility will commence in 2015 and is expected to be available by mid-2016, in advance of Painted Pony's production requirements. Upon completion of the first phase of the strategic alliance, further opportunities for the build-out of additional natural gas and NGL processing infrastructure in northeast British Columbia are expected.

Acquisition of Petrogas

On October 1, 2013, AltaGas purchased a 25 percent ownership interest in Petrogas, a leading integrated North American midstream company. On March 1, 2014, AltaGas increased its effective ownership in Petrogas to 33⅓ percent by transferring its 25 percent interest to AIJVLP concurrently with AIJVLP acquiring an additional 41⅔ percent interest in Petrogas, such that AIJVLP has a 66⅔ percent interest in Petrogas. As a result Petrogas is now owned one-third by each of AltaGas, Idemitsu and its original shareholder. This transaction was reported on SEDAR (www.sedar.com) by way of a Business Acquisition Report dated May 30, 2014.

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

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

In 2012, AltaGas acquired DEI for $34.7 million. DEI was 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 each fully contracted with a long term PPA and REPA, respectively.

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 REPA 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 in, 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 2012, AltaGas completed the second 15 MW cogeneration facility at Harmattan. 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 Blythe, which owns 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.

In 2014, AltaGas commissioned the 195 MW Forrest Kerr and 16 MW Volcano Creek facilities. The 66 MW McLymont Creek facility will be the third and final Northwest Project to come online, with commissioning expected in mid-2015. The three Northwest Projects have a combined generating capacity of approximately 277 MW.

On December 1, 2014, AltaGas disposed of 25 MW of gas-fired peaking capacity for cash proceeds of approximately $35 million before adjustments for working capital. These assets were purchased from Maxim Power Corp. in 2012.

In 2014, AltaGas acquired Blythe II. Development activities are underway for the new site and could potentially result in doubling the existing 507 MW of generation capacity in California. Blythe III was also purchased, for approximately US$1.5 million, for a possible further expansion of generation capacity in California.

Effective January 8, 2015, AltaGas acquired three U.S. gas-fired power assets with a total generation capacity of 164 MW. Two of the facilities are located in California and the third is located in Colorado. All three assets are currently contracted under PPAs with local creditworthy utilities, and generate stable cash flows.

Development of the Utilities Business

Acquisition of SEMCO

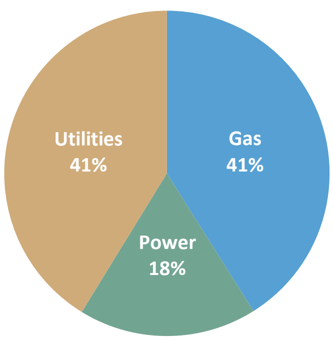
On August 30, 2012, AltaGas and AUH(US) closed the acquisition of SEMCO. AUH(US) acquired all of the issued and outstanding SEMCO Shares for aggregate consideration of US$1,156,000,000, before adjustment, including approximately US$371,000,000 in assumed debt. SEMCO Energy, a regulated public utility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

The CINGSA Storage Facility was completed in 2012 and customer withdrawals began in November 2012.

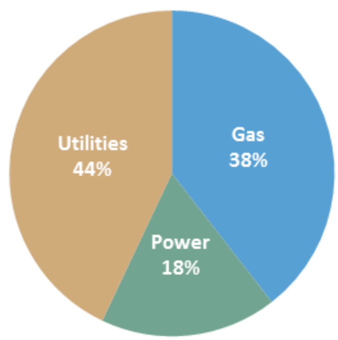
BUSINESS OF THE CORPORATION

AltaGas' net revenue for the 12-month period ended December 31, 2014 was $1,019 million compared to $960 million for the 12-month period ended December 31, 2013.

Net Revenue by Business for 2014 (1)(2)



Net Revenue by Business for 2013 (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, field gathering and processing, transmission and energy services. The Power segment consists of power generation assets across five fuel types: gas, coal, run-of-river, wind, and biomass. 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 $425 million for the year ended December 31, 2014, representing approximately 41 percent of AltaGas' total net revenue before Corporate segment and intersegment eliminations.

GAS BUSINESS – EXTRACTION

AltaGas' extraction business includes 100 percent ownership of Harmattan 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, Harmattan 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, 2014.

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 – an application by NGTL to the NEB proposing that the extraction rights be transferred to the receipt shippers on the NGTL system 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, 2014, approximately 70 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, 2014, approximately 30 percent of AltaGas' NGL production (13 percent of total extraction production) was sold under contracts subject to frac spread. If commodity prices or operating costs make NGL extraction uneconomical, the NGLs may be 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	7.17	79	Non-Operated
Empress Pembina	11.25	135	Non-Operated
JEEP	100.00	250	Operated
Younger	56.67	425	Operated
Harmattan	100.00	490	Operated
Total(1)		**1,569**	

Note:

(1) Excludes Bantry fractionator products and field NGLs.

Total Liquids Production (Bbls/d)(1)(2)		
	2014	**2013**
NGLs	27,369	24,490
Ethane	37,811	34,115

Notes:

(1) Excludes 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 7.17 percent at December 31, 2014. The remaining 92.83 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' 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 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. The NGL purchase agreement expires in 2018 and Pembina has an option to prepay for an ownership change in 2017.

Extraction – Harmattan

AltaGas owns a 100 percent interest in Harmattan 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.

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

At Harmattan, natural gas processing services are provided to approximately 70 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 32 percent of the natural gas volume processed at Harmattan is done under the terms of the Rep Agreements which have life-of-reserves dedications. The balance of the raw natural gas processed at Harmattan 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.

Management has identified environmental issues associated with the prior activities of Harmattan. An environmental allocation agreement is in place with the former operator which allocates the liability. This agreement significantly reduces any soil contamination liability and eliminates any groundwater contamination liability to AltaGas. See "*Risk Factors*" below.

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.

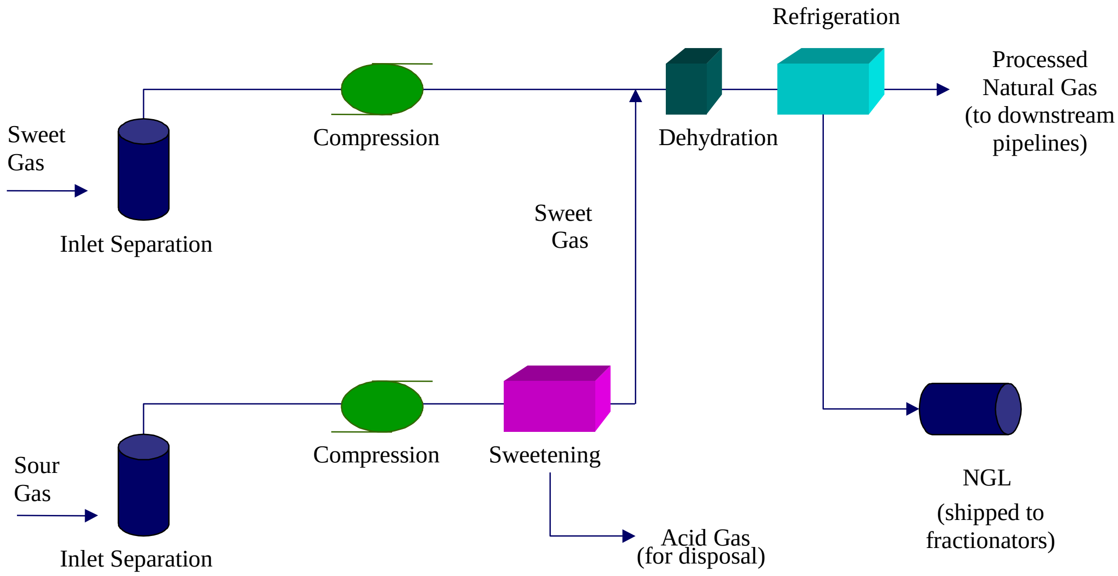
Harmattan is well-positioned as the high-volume, low-cost processing facility in its service area. Harmattan is a significant service provider with a large capture area in west central Alberta. Many other facilities in the Harmattan area are currently underutilized, providing AltaGas with opportunities 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.

GAS BUSINESS – FIELD GATHERING AND PROCESSING and TRANSMISSION

The Field Gathering and Processing business consists of approximately 70 gathering and processing facilities in western Canada and approximately 6,100 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 19% 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, with several facilities having the benefit of take-or-pay contracts. 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"*. AltaGas has NGL extraction capability at 32 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, at several facilities on a take-or-pay basis.

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

	2014	2013
Capacity (gross Mmcf/d)[(1)(2)]	1,355	1,384
Throughput (gross annual Mmcf/d)[(2)]	419	420
Capacity utilization (%)	31	30

Notes:

(1) As at December 31, 2014 and 2013.

(2) Gross numbers are not adjusted to reflect AltaGas' working interest.

Average facility utilization increased to 31 percent in 2014 from 30 percent in 2013. AltaGas experienced increased throughput, primarily due to continued growth at its two largest facilities, Gordondale and Blair Creek, offset by the sale of the Ante Creek 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 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 2014 AltaGas conducted business with more than 200 customers in its Field Gathering and Processing operating areas. The Field Gathering and Processing business's top 10 customers represented approximately 9 percent of total AltaGas consolidated net revenue for 2014.

Field Gathering and Processing - Contracts

AltaGas gathers and processes natural gas under contracts with natural gas producers. There are approximately 800 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 acquire or develop 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 or constructed, 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 of facilities prior to acquisition.

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, 2014 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 because 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 2014 AltaGas processed an average of 419 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, including plans to develop LNG and LPG export capacity and make such capacity available to producers, 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.

Transmission – Business Description

AltaGas owns four natural gas transmission systems with transportation capacity of approximately 559 Mmcf/d, and owns three NGL pipelines and leases one NGL pipeline with combined capacity 189,300 Bbls/d.

The following table provides a summary of the gross capacity of AltaGas' transmission pipelines at December 31, 2014. 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	99.5	100 Mmcf/d	285	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[4]	NGL	Central Alberta	nil	37,700 Bbls/d	32	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.
(4) BDS is leased from Nova Chemicals, which terminates March 31, 2017.

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 Limited 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 145,341 GJ/d in 2014. 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 pipeline 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 EDS and JFP transportation agreements have an initial term of 12 years to 2017 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 and JFP. The fixed-fee is subject to an interest rate adjustment every three years based on then-current interest rates. The EDS and JFP transportation agreements also contain 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 and JFP transportation agreements 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 pipelines 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 has provided notice that it intends exercise its option to purchase the pipelines effective March 15, 2017.

The BDS is used to transport butane from Edmonton to Fort Saskatchewan. The BDS is a 32 km pipeline, with capacity of 37,700 Bbls/d.

Transmission – Cold Lake, Kahntah, Summerdale and Porcupine Hills

AltaGas owns and operates the majority of the Cold Lake natural gas transmission system, which consists of 21 receipt points and 31 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. In 2013, AltaGas began construction of the Cold Lake Pipeline Expansion. The first portion of the Cold Lake Pipeline Expansion was completed in fourth quarter 2013 and the second portion was completed in fourth quarter 2014. The Cold Lake Pipeline Expansion is 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.

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 – 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 – 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 energy services business manages AltaGas' 50 percent share of Sarnia Airport Storage Pool Limited Partnership, which owns 5.3 Bcf of gas storage capacity. AltaGas seeks 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 entered into an agreement for the acquisition of the remaining 50 percent ownership interest in Alton Natural Gas Storage L.P., which owns the 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 L.P. pursuant to the acquisition of Landis Energy Corporation in 2010. In October 2014, Heritage Gas executed a 20 year gas storage agreement with Alton Natural Gas Storage L.P. Construction of Alton commenced in second quarter 2014. The issuance of permits to commence brining has been delayed. AltaGas continues to work with the regulatory agencies to obtain the required permits and expects to recommence project activities in 2015.

Energy Services - Customers

AltaGas energy service customers are C&I, agricultural and institutional end-users in British Columbia, Alberta, Saskatchewan, Manitoba, Ontario and Quebec. Customer retention rates are approximately 80 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 total AltaGas consolidated revenue during 2014.

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.

GAS BUSINESS – ENERGY EXPORT

On March 1, 2014, AIJVLP completed the acquisition of two-thirds of Petrogas. Petrogas is a privately-held leading North American integrated midstream company. Petrogas' extensive logistics network provides key infrastructure as well as supply logistics and marketing expertise required to pursue LPG export opportunities.

On May 1, 2014 Petrogas acquired Ferndale. The facility is expected to ramp-up over the next several years to approximately 30,000 Bbls/d. Tank inspections were completed in late 2014. The facility has been re-configured to handle propane. First propane shipments are expected by mid-2015.

Through AIJVLP, AltaGas is also developing a greenfield LPG terminal on the west coast of Canada and is currently conducting site evaluation studies, which are expected to be completed in 2015. Terminal sites and refrigeration technology are being evaluated. AIJVLP is currently in discussions with key stakeholders to determine project timing, and with market participants to develop sales and logistics agreements.

In addition to pursuing LPG export initiatives through AIJVLP, AltaGas, Idemitsu, EDFT and EXMAR formed the Consortium to support the plan of arrangement under CCAA proceedings for the Douglas Channel LNG project. The Douglas Channel LNG project is a proposed barge-based LNG export facility on the west bank of the Douglas Channel in Kitimat, British Columbia with an initial nameplate capacity of 0.55 million tonnes per annum of LNG. On January 28, 2015, the Consortium announced that it had obtained full ownership and control of the Douglas Channel LNG project as a result of the plan of arrangement completed under CCAA proceedings. The Consortium has executed long-term lease agreements with the Haisla Nation regarding land and water tenure and with PNG for long-term pipeline capacity to supply gas to the project. AltaGas will act as the project manager of the Douglas Channel LNG project.

Separately, AIJVLP continues to make progress on the development of a second LNG export facility. On April 16, 2014, Triton LNG, a wholly-owned subsidiary of AIJVLP, received NEB approval to export up to 2.3 million tonnes per year of LNG. The LNG export projects are subject to consultations with First Nations, and the completion of the feasibility study, siting, permitting, regulatory approvals and facility construction.

POWER BUSINESS

AltaGas' Power business contributed net revenue of $185 million for the year ended December 31, 2014, 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, 2014, AltaGas had 1,285 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, 223 MW of run-of-river generation capacity, 117 MW of wind power generation capacity, 35 MW of biomass generation, 30 MW of cogeneration capacity in Alberta, and 20 MW of gas-fired peaking capacity.

At December 31, 2014, AltaGas' 403 MW of installed power capacity in Alberta represented approximately 3 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 strategy has already been furthered in 2015 with the acquisition of three western U.S. gas-fired power assets with a total generation capacity of 164 MW. For the coming years, AltaGas has approximately 2,340 MW of renewable and gas-fired power generation projects in various stages of construction and development. The development projects consist of 1,087 MW of wind power developments and 1,253 MW of gas-fired generation under development. 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 gas-fired generation is targeted for California, and the run-of-river projects are all located in British Columbia.

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

Power Prices and Volumes	2014	2013
Volume of power sold (GWh)(1)	5,169	4,458
Average price received on the sale of power ($/MWh)(1)(2)	65.97	76.82
Alberta Power Pool average spot price ($/MWh)(1)	49.42	80.19

Notes:
(1) Power sold from Sundance B is disclosed as volumes based on target availability and not volumes delivered
(2) Price received excludes Blythe as it earns fixed capacity payments under is PPA with SCE

Gas-Fired Generation

Effective May 16, 2013, AltaGas purchased Blythe, which owns the 507 MW Blythe Energy Center combined cycle power plant in southern California, for US$515 million before adjustments for working capital. The Blythe Energy Center 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 transmission grid operated by the CAISO, 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 transmission grid operated by the CAISO via a 67-mile transmission line owned by Blythe. 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. In 2014 Blythe entered into a long-term agreement with Siemens for the maintenance of the two existing combustion turbines. In 2014 AltaGas also acquired Blythe II and Blythe III to provide further opportunities to expand. Development activities are underway for the new sites and could potentially result in tripling AltaGas' generation capacity in the vicinity of the Blythe Energy Center.

AltaGas currently has 30 MW of cogeneration capacity in Alberta. In 2010, AltaGas commissioned a 15 MW cogeneration facility at Harmattan. The facility consists of a gas turbine which drives a 15 MW generator for delivery of electricity into the Alberta power market, as well as a heat recovery steam generator that is capable of producing all of the steam required to process gas at Harmattan from the waste heat in the exhaust gases from the turbine. In 2012, AltaGas completed a second 15 MW cogeneration facility at Harmattan. 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. Construction of Cogeneration III is advancing and the project remains on schedule, with an expected in-service date in the first half of 2015.

AltaGas has 20 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. Effective December 1, 2014 AltaGas sold these assets.

In 2014 the existing generation equipment at the Parkland gas-fired peaking facility was replaced, increasing the overall capacity by 3MW while improving the overall efficiency and reliability of the facility. 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.

On January 8, 2015, AltaGas completed the acquisition of three western U.S. gas-fired power assets with a total generation capacity of 164 MW. Two of the facilities are located in California and the third is located in Colorado. The 49.5 MW Ripon facility is located east of San Francisco in the city of Ripon, the 44.5 MW San Gabriel facility is located east of Los Angeles in the city of Pomona, and the 70 MW Brush facility is located northeast of Denver in the city of Brush. All three assets are currently contracted under PPAs with local creditworthy utilities, and generate stable cash flows. The acquisition is consistent with AltaGas' strategy of capitalizing on the demand for clean energy sources such as natural gas, growing and diversifying the power portfolio by increasing AltaGas' presence in the California and Colorado power markets, providing low-risk, fully contracted cash flows, and providing the potential for future organic growth opportunities via repowering of the sites.

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 ASTC Partnership. Each partner owns a 50 percent share of ASTC Partnership. There is a Sundance B3 PPA and a Sundance B4 PPA, one for each of Units 3 and 4 at the Sundance Plant. 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.

ASTC Partnership started dispatching power effective December 29, 2001. AltaGas maintains the books and records of 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 pairs for PPA purposes: Sundance A - Units 1 and 2, Sundance B - Units 3 and 4, and Sundance C - Units 5 and 6. Sundance B 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, ASTC Partnership will be compensated when power production is less than target levels, at a rate based on RAPP, as described in more detail later in this section. AltaGas recognizes its share of ASTC Partnership income through equity accounting.

Under the Sundance B3 and B4 PPAs, 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 ASTC Partnership to communicate the volume of power available and the price of the power to the AESO. 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 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 Partnership 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 Partnership 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 2014. 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 Partnership is obligated to pay TransAlta based on the difference between actual availability and target availability, multiplied by RAPP. ASTC Partnership pays transmission charges based on actual power delivered. During these under or over-generation periods AltaGas has financial exposure to the difference between the Pool 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.

There are financial incentives available to TransAlta 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.

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 each fully contracted with a long-term PPA and REPA respectively.

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 sells them, and intends to continue to sell them, to provide an additional revenue stream.

Bear Mountain Wind Park is owned 100 percent by BMWLP, a wholly-owned subsidiary of 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 REPA 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, totaling 408 MW. AltaGas also has 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.

Run-of River Hydroelectric Generation

In 2014, construction was completed for the 195 MW Forrest Kerr facility and 16 MW Volcano Creek facility and both were commissioned. The Forrest Kerr facility was the largest project in AltaGas' 20 year history and the Volcano Creek facility was constructed and commissioned a full two years ahead of schedule. The 66 MW McLymont Creek facility will be the third and final Northwest Project to come online, with commissioning expected in mid-2015. The Northwest Projects have a combined generating capacity of approximately 277 MW. The Northwest Projects are contracted with 60-year EPAs with BC Hydro that are fully indexed to CPI. Impact Benefit Agreements are in place for all three Northwest Projects, ensuring a cooperative and mutually beneficial relationship between the Tahltan First Nation and

AltaGas. 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 Northwest Projects will be the anchor tenant for the NTL.

Effective July 10, 2012 AltaGas (through PNG) 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.

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.

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 which is generally built at a much higher cost than the Sundance B plant. Power prices have come under pressure recently as significant new supply has been added to the Alberta system. Demand growth has been strong at approximately 3%, and at that rate we would expect the supply/demand balance to return to historical norms in approximately 2-3 years. AltaGas remains confident in the ongoing long-term 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. Similarly, power sold from the Forrest Kerr facility and Volcano Creek facility is sold at a predetermined price as contracted under the 60-year EPAs with BC Hydro. The EPAs for Forrest Kerr and Volcano Creek are fully indexed to 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 that expire August 2027 (with automatic one year renewals unless terminated) and December 31, 2017, respectively. The Ripon facility is contracted by Pacific Gas & Electric Company under a PPA until May 31, 2018. The Brush facility is contracted by Tri-State Generation and Transmission Association, Inc. until December 31, 2019. The San Gabriel facility is contracted by SCE under a PPA until January 2, 2016.

UTILITIES BUSINESS

AltaGas' Utilities business contributed net revenue of $430 million for the year ended December 31, 2014, representing approximately 41 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 Northwest Territories utility business. 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.

For AUI, the regulator approves distribution rates under a Performance Based Regulation (PBR) model that commenced January 1, 2013 with an initial term of five years (2013 to 2017). Under this model, revenues are set by formula. Specifically, revenues in each year are based on the last approved rates and are increased each year by a formula reflecting customer growth and 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.

Inuvik Gas is regulated on a complaint basis and sets its rates to be market competitive.

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 a gas utility business consisting of rate regulated natural gas transmission and distribution to its customers, and gas storage. SEMCO Energy's gas utility business, including the 65 percent ownership interest in CINGSA, accounted for approximately 99 percent of SEMCO Energy's 2014 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 utility 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 utility business is 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 and CINGSA’s services provided to its Alaska customers. 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.

	2014	**2013**
Approved return on equity (%)		
Utilities Canada (average)	9.7	10.0
Utilities US (average)[1]	11.2	11.3

	2014	2013
Approved return on debt (%)		
Utilities Canada (average)	5.9	6.1
Utilities US (average)(1)	5.3	5.6
Rate base ($ millions) (1)		
Utilities Canada	677	605
Utilities US (2) (3)	818	773

Notes:

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

(2) In US dollars.

(3) Reflects SEMCO Energy's 65 percent interest in CINGSA. The rate base excludes gas in storage for ENSTAR. Currently ENSTAR is compensated for its gas in storage of $51 million (2013: $53 million) through a carry cost component. ENSTAR has filed to incorporate the gas in storage as part of its rate base in the current rate case before the RCA. It has yet to be determined if ENSTAR will prevail in its request to include gas in storage in base rates. The decision on the rate case is expected in the fourth quarter of 2015.

AUI

AUI commenced operations as an Alberta, provincially regulated, natural gas distribution utility in 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 a few consumers choosing alternate fuel sources or living in remote areas where natural gas service is cost-prohibitive. The Alberta natural gas distribution market is dominated by a major distributor that serves approximately 85 percent of natural gas consumers. AUI serves approximately 6 percent of Alberta customers, with the remaining market served by member-owned natural gas cooperatives and municipally owned systems.

Within its existing franchise areas AUI averaged annual growth of 2.4 percent in 2012, 1.9 percent in 2013 and 2.2 percent in 2014. AUI currently expects annual growth in new service sites of approximately 2.0 percent in 2015, with similar growth continuing in subsequent years.

AUI pursues opportunities to develop service areas not currently served with natural gas. Current expansion opportunities represent relatively minor asset growth; but AUI remains committed to its strategy of pursuing expansion projects meeting 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, 2014, and 2013 are shown in the following table:

($ millions)	2014	2013
New business	10.0	6.4
System betterment and gas supply	21.4	13.9
General plant	4.6	6.7
Total	**36.0**	**27.0**

Operations

AUI's distribution system consists of 20,767 km of pipeline, operating at pressures ranging from 200 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 721 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 2014, the total throughput of natural gas delivered to 76,454 end consumer service sites and transported to three producers had a total energy value of approximately 21.4 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 totalled 1,736 in 2014 and 1,442 in 2013. Of the 21.4 PJ of natural gas AUI delivered through AUI's system in 2014, 11.4 PJ was attributed to 60,146 non-demand service sites that received default gas supply under the regulated rate, 4.6 PJ to 16,253 non-demand service sites that received gas supply from natural gas retailers, 3.2 PJ to 55 demand-based service sites and 2.2 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 distribution service.

AUI Revenue by Service Type[(1)]

(%)	**2014**	**2013**
Residential	56.0	54.9
Commercial	23.1	24.2
Rural[(2)]	17.1	17.0
Demand	3.8	3.9
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 at December 31, 2014, 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	64.0	1.8 years
Indian and Northern Affairs Canada Permits	9	1.6	Varying
Gas Distribution Act Franchises	16	33.3	Perpetual
Métis Settlement Operating Agreements	4	1.1	0.3 years

The top three municipalities contributing to AUI’s total net revenue in 2014 were the City of Leduc, Town of Beaumont and Town of Drumheller. Collectively, these municipalities accounted for approximately 23 percent of AUI's total net revenue and 19 percent of energy delivered in 2014.

Seasonality

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

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

	2014				2013			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	1,719	170	622	2,342	1,958	126	580	2,103
Degree Days - normal	1,774	190	562	2,220	1,762	206	563	2,212

2014 AUI Regulatory Overview

In Decision 2012-237, issued September 2012, the AUC approved a revenue cap per customer formula for AUI. Under the formula, base revenue is adjusted annually by escalating base revenue per customer from the previous year by an inflation factor ("I") less a productivity improvements factor ("X") and applying the escalated revenue per customer amounts to the forecast number of customers for the upcoming year. The year-over-year percentage change in number of customers is referred to as the "Q" Factor. This (I-X)*Q formula is referred to as the annual PBR escalation factor applied to base revenue.

In addition to base revenue, the PBR plan includes mechanisms for recovery of costs:

- determined to flow through directly to customers ("Y Factor adjustments");
- related to material unforeseen events ("Z Factor adjustments"); and
- related to major capital projects not otherwise funded under the PBR formula ("K Factor adjustments" or "capital tracker adjustments").

Generally, these adjustments are applied for, and approved on, an interim basis based on forecast costs. They are subsequently adjusted and finalized based on actual costs.

For 2014, the AUC approved an annual PBR escalation factor of 3.31% applied to base revenue. In addition, AUI received interim approval for recovery of $1.6 million in Y Factor adjustments related to Natural Gas Settlement System Code ("NGSSC") costs required for compliance with AUC Rule 028, income tax timing differences and external regulatory costs. AUI also obtained interim approval for recovery of K Factor adjustments related to $18.6 million in specified pipe replacement, station refurbishment and gas supply investments. The Y Factor and K Factor adjustments are expected to be finalized in 2015 based on actual costs and AUC directed adjustments, if any.

For 2015, the AUC approved an annual PBR escalation factor of 3.48% applied to base revenue. In addition, AUI received interim approval for recovery of $1.9 million in Y Factor adjustments related to NGSSC system costs, income tax timing differences and external regulatory costs. AUI also obtained interim approval for recovery of K Factor adjustments related to $21.6 million in specified pipe replacement, station refurbishment and gas supply investments. The Y Factor and K Factor adjustments are expected to be finalized in 2017 based on actual costs and AUC directed adjustments, if any.

A decision on the 2013 Generic Cost of Capital ("GCOC") proceeding is pending and expected before the end of the first quarter of 2015. The decision will establish the return on equity and capital structures for all AUC regulated utilities for 2013, 2014 and, possibly, future years. In the interim, the AUC has approved continued use of the 2011 and 2012 ROE of 8.75 percent as a placeholder.

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 seven 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 currently fifth in market share in Nova Scotia. 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, Heritage Gas believes that it will continue to expand its customer service base within the Nova Scotia market.

In 2012, Heritage Gas began to develop a CNG loading and unloading system to allow customers not connected through the traditional pipeline distribution infrastructure to gain access to natural gas. This type of CNG system is new to Nova Scotia but it has been in operation in other regions of Canada for several years. Operations began in May 2013 and to date the CNG business has been developed and operated as a non-regulated business. However, in December 2014 Heritage Gas received approval from the NSUARB to expand its regulated operations into Antigonish County. Heritage Gas intends to serve this new market using CNG, which would result in a portion of the CNG business being subject to regulation once the Antigonish distribution system is in operation.

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 2014 there were approximately 18,500 potential customer meters of whom approximately 6,500 were commercial energy consumers and 12,000 were residential energy consumers with access to the Heritage Gas distribution system. Of the 18,500 potential customer meters, Heritage Gas had approximately 5,800 customer meters activated by December 31, 2014. 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 (%)	**2014**	**2013**
Activated residential	24	23
Activated commercial	44	43
All customers	31	30

In 2014, Heritage Gas connected 733 new customers, compared to 723 in 2013.

Capital expenditures by Heritage Gas for the years ended December 31, 2014 and 2013 are shown in the following table:

($ millions)	**2014**	**2013**
New business	33.8	30.5
General plant	0.9	0.9
CNG	0.8	8.7
Total	35.5	40.1

In 2014 Heritage Gas invested $35.5 million to continue the expansion of its network. The major focus was the continued expansion in the Halifax Regional Municipality where Heritage Gas added 30 kilometers of network infrastructure and the expansion to a new franchise market in Pictou County. Included in the capital expenditure is $0.8 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 revenue deficiency account (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, 2014 and 2013 is shown in the following table:

Revenue Deficiency Account	**2014**	**2013**
($ millions)	33.4	40.0

Operations

On December 31, 2014, Heritage Gas' distribution system consisted of approximately 420 km of pipeline mains infrastructure of which approximately 330 km was located in the Halifax Regional Municipality, approximately 60 km was located in Amherst, 20 km in New Glasgow/Pictou area and approximately 10 km was located in Oxford.

Heritage Gas purchases gas under negotiated contracts with wholesale gas marketers. During 2014, Heritage Gas entered into five new contracts to manage its gas supply needs and to provide stability during the winter months. The contracts have various ending dates ranging from October 31, 2014 to October 31, 2015. 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.

Heritage Gas has received much of its natural gas supply from the Sable Offshore Energy Project off the coast of Nova Scotia. The natural gas supply from the Sable Offshore Energy Project is expected decline in the coming years. As such, Heritage Gas continues to evaluate alternatives including gas storage and upstream transportation options to help ensure security of gas supply for its customers.

In October 2014, Heritage Gas executed a 20 year gas storage agreement with Alton Natural Gas Storage L.P., a wholly-owned subsidiary of AltaGas, which commenced construction in second quarter 2014 on the 10 Bcf Alton underground gas storage facility near Truro, Nova Scotia. Subject to timely receipt of regulatory approvals, the storage service is scheduled to commence in 2019.

Also in October 2014, Heritage Gas signed an agreement with Spectra Energy for the Atlantic Bridge Project, on the Algonquin Gas Transmission pipeline system. The contract is a 15-year commitment that provides Heritage Gas an opportunity to diversify suppliers and provide access to other supply basins. The expected in-service date is in the fall of 2017.

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.

	2014				**2013**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	1,184	136	778	2,027	1,405	126	645	1,925
Degree Days - normal	1,292	138	750	1,952	1,284	138	650	1,966

2014 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 resulted 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. Heritage Gas has not applied for updated rates for 2015 and continues to assess if they will apply for a change to rates for 2016 or later.

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 took service in first quarter 2014.

In response to a November 6, 2013 application by Heritage Gas, on February 20, 2014, the NSUARB issued a ruling that prudently incurred costs of natural gas storage may be included within Heritage Gas' cost of service. The Alton service is anticipated to provide benefits to Heritage Gas and its customers in the form of security of gas supply, enhanced reliability and delivery of natural gas during the peak heating season, as well as reduced natural gas price volatility. In December 2014 Heritage submitted an application to the NSUARB for approval of the natural gas storage costs associated with the Alton project and the method of recovery and allocation of those costs. Heritage expects a decision on the application within the first half of 2015. Subject to timely receipt of regulatory approvals, the storage service is scheduled to commence in 2019.

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 kilometers of main pipelines and approximately nine kilometers 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 un-serviced rural areas. However, in 2013 PNG commenced development of a project to expand the capacity of its transmission line. PNG has entered into 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 $11.5 million of development activity for PLP was recorded in 2014, with such amounts recorded as accounts receivable until such time that a definitive decision is made to proceed with construction of the project. PNG expects to continue its environmental and consultation processes throughout 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, 2014 and 2013 are shown in the following table:

($ millions)	**2014**	**2013**
New business	2.7	3.8
System betterment and gas supply	5.9	6.1
General plant	1.5	2.3
Total	10.1	12.2

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, a methanol/ammonia facility in Kitimat ceased operations in 2005. These facilities will continue to be maintained for potential future use, but are not forecast to be utilized in 2015.

On December 12, 2014, EDFT executed a 20 year Gas Transportation Service Agreement with PNG for pipeline capacity to supply gas to the Douglas Channel LNG project. If service commences under the Gas Transportation Service Agreement with EDFT, 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. PNG can give no assurances as to if or when the capacity relating to this Gas Transportation Service Agreement will be utilized. Should the project proceed, service is expected to commence sometime in 2018.

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 Limited 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 Limited 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 9.7 PJ in 2014 compared with 9.0 PJ in 2013. Deliveries to residential customers in 2014 increased by approximately 10 percent compared to 2013 mainly due to an increase in the number of customers as well as winter temperatures that were much colder than 2013. Deliveries to commercial customers also increased in 2014 by approximately 6.5 percent from 2013 levels due to the colder winter weather and increased commercial activity in PNG's service areas.

Deliveries to small industrial customers in 2014 increased by approximately 8 percent compared to 2013. This was mainly due to volumes from a new small industrial customer in Dawson Creek offset by lower volumes to various customers in the Fort St. John service area. Large industrial customers' deliveries decreased approximately 5 percent from 2013 to 2014, reflecting the slightly lower volumes taken by PNG's largest industrial customer who is in the process of modernizing its facilities. The decrease in deliveries to the large industrial customers 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.

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

	2014	2013
Deliveries: (in PJ)		
Residential	3.3	3.0
Commercial	3.0	2.8
Small industrial	2.7	2.4
Large industrial	0.7	0.8
Total deliveries	9.7	9.0

	2014	2013
Customers at Year End:		
Residential	35,348	34,914
Commercial	5,335	5,269
Small industrial	53	55
Large industrial	2	2
Total customers	40,738	40,240

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) recently renewed its franchise agreement with the City of Dawson Creek for a further term of 21 years expiring on December 31, 2036. 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.

2014 PNG Regulatory Overview

In November 2014, PNG(NE) filed its 2015 revenue requirements application for its Fort St. John/Dawson Creek divisions. The application sought approval to increase rates on an interim basis effective January 1, 2015 pending the BCUC's review of the applications. The BCUC approved interim rates effective January 1, 2015 at the levels set forth in the application. The 2015 revenue deficiency projected for the FSJ/DC division is approximately $0.5 million. The applied for delivery charge change compared to the December 2014 delivery rate for an average residential customer in this service area is an increase of 4.9 percent. For PNG West and PNG(NE) TR, PNG filed a letter application requesting that the 2014 rates remain in effect for 2015 and any potential increases or decreases in its cost of service be addressed through a deferral account to be amortized during 2016. A negotiated settlement process (NSP) is expected to be conducted with respect to the 2015 revenue requirements application in the second quarter of 2015. The 2014 delivery rates were approved under a NSP.

PNG was 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. On March 25, 2014, the BCUC issued its decision on the Generic Cost of Capital (GCOC) Stage 2 proceeding. The approved common equity ratio for PNG West and PNG(NE) TR division was set at 46.5 percent compared to the previously approved ratios of 45 percent and 40 percent respectively. The approved common equity ratio for PNG(NE) FSJ/DC division was set at 41 percent compared to the previously approved ratio of 40 percent. The BCUC also established an equity risk premium of 75 bps for PNG West and PNG(NE) TR division and an equity risk premium of 50 bps for PNG(NE) FSJ/DC division. This resulted in an allowed ROE of 9.50 percent for PNG West and PNG(NE) TR and 9.25 percent for PNG(NE) FSJ/DC effective January 1, 2013. These common equity ratios and allowed ROEs were in effect for 2014 and will remain the same for 2015.

Inuvik Gas and Ikhil Joint Venture

Inuvik Gas is a corporation equally owned ⅓ each by an AltaGas subsidiary, the Inuvialuit Petroleum Corporation, and ATCO Midstream NWT Ltd. The Ikhil Joint Venture is owned by an AltaGas subsidiary (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.

The Ikhil Joint Venture has historically supplied 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, a propane air mixture system producing synthetic natural gas is currently the main source of energy supply for Inuvik Gas with Ikhil Joint Venture serving as a back-up. Effective August 8, 2014 Inuvik Gas extended its gas distribution franchise with the Town of Inuvik for a period of ten years. Inuvik Gas, with the assistance of its shareholders, continues to pursue alternative long-term energy sources for Inuvik Gas.

At the end of 2014 Inuvik Gas provided service to 930 residential and commercial customers, the same number as in 2013.

SEMCO ENERGY

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

SEMCO GAS

In Michigan, SEMCO Gas distributes natural gas to approximately 295,000 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 0.7 percent annually during the past three years (with an increase of 0.8 percent in 2014). 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, 2014 and 2013 are shown in the following table:

(US$ millions)	**2014**	**2013**
New business	8.6	7.6

System betterment and gas supply	22.7	28.2
General plant	3.7	2.6
Total	35.0	38.4

Operations

The SEMCO Gas natural gas transmission and delivery system in Michigan includes approximately 151 miles of gas transmission pipelines and 6,055 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:

	2014	**2013**
Deliveries: (MDTH)		
Residential	27,768	25,355
Commercial	14,547	12,391
Transport	18,655	18,190
Gas Customer Choice(1)	3,668	4,110
Total deliveries	64,638	60,046

	2014	**2013**
Customers at Year End:		
Residential	256,649	252,209
Commercial	23,276	22,322
Transport	255	256
Gas Customer Choice(1)	15,252	18,477
Total customers	295,432	293,264

Notes:

(1) 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.

	2014				**2013**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	2,412	246	947	3,988	2,496	206	984	3,324
Degree Days - normal	2,294	170	862	3,214	2,242	163	845	3,181

2014 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. In September 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 ("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 generated 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.

SEMCO Gas filed an MRP case on January 23, 2015. The regulatory proceedings on the MRP case are expected to take between 6-12 months. As part of the case, SEMCO is requesting to continue the MRP program for an additional five years. The anticipated annual average capital spending over the five year period is approximately US$10 million with the average annual revenue, collected from customers in a monthly surcharge, anticipated to be approximately US$8.5 million.

An investigation into a 2004 house fire in SEMCO Gas' 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 49,000 of these valves as of December 31, 2014, under the Valve Replacement Program. As of December 31, 2014, SEMCO Gas has incurred approximately US$4.4 million of valve replacement costs. 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 139,000 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 LNG plant. ENSTAR's service area encompasses over 58 percent of the population of Alaska.

The average number of customers at ENSTAR has increased by an average of approximately 1.2 percent annually during the past three years (with an increase of 1.5 percent in 2014). 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, 2014 and 2013 are shown in the following table:

(US$ millions)	**2014**	**2013**
New business	14.5	12.6
System betterment and gas supply	12.4	7.8
General plant	2.9	2.3
Total	29.8	22.7

Operations

ENSTAR's natural gas delivery system (including SEMCO Energy's Alaska Pipeline Company) includes approximately 425 miles of gas transmission pipelines and 2,970 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 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. In 2013, the LNG export plant obtained a new export license to export approximately 40 Bcf from Cook Inlet over the course of two years. In light of the relative stability of its gas supply, ENSTAR did not oppose this application.

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

	2014	**2013**
Sales and Deliveries: (in Mmcf)		
Residential	17,547	19,034
Commercial	12,399	13,333
Transport	18,687	19,109
Total deliveries	48,633	51,476

	2014	**2013**
Customers at Year End:		
Residential	126,053	123,941
Commercial	12,581	12,402
Transport	18	16
Total customers	138,652	136,359

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.

	2014				**2013**			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Degree Days - actual	3,189	828	1,512	3,563	3,518	845	1,848	3,680
Degree Days - normal	3,565	903	1,638	3,884	3,565	903	1,638	3,884

2014 ENSTAR Regulatory Overview

The rates charged to customers in ENSTAR's service territories have an RCA-approved gas cost adjustment pricing mechanism. The gas cost adjustment pricing mechanism 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 2014, ENSTAR obtained permission from the RCA to file its gas cost adjustment on an annual, instead of a quarterly, basis.

In September 2014, ENSTAR and Alaska Pipeline Company filed with the RCA a base rate and rate design case based on data from a test year ended December 31, 2013. In that filing, ENSTAR requested an increase of US$15.1 million in base rate revenue on a normalized annual basis. These new rates reflect the addition of approximately US$115.0 million in gross rate base ENSTAR has invested since its 2009 rate case to ensure the ongoing safe and reliable delivery of natural gas. ENSTAR proposed to increase its rates in two steps: (i) an interim and refundable rate increase of approximately 1.0% of total revenues to be effective for billings on or after November 1, 2014; and (ii) an additional increase of approximately 4.06% upon final approval or acceptance, bringing a permanent rate increase of approximately 5.06% of total normalized annual revenues. The second increase is not expected to be approved and implemented until fourth quarter 2015. In October 2014, the RCA approved ENSTAR’s request for an interim and refundable rate increase to be effective November 1, 2014. A procedural schedule for the case has been adopted which provided for a public hearing on the rate request to begin in August 2015. The statutory deadline for the RCA to rule on the request is December 11, 2015.

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 CINGSA 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 firm storage capacity of the CINGSA Storage Facility.

CINGSA commenced "free-flow" injections into the CINGSA 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.

Following drilling of one of CINGSA’s storage wells, CINGSA determined that it had discovered a pocket of approximately 14.5 Bcf of native gas. Discovery of this native gas has enhanced facility performance, but not all of the native gas is necessary for storage operations. CINGSA may pursue sales of the native gas; it is seeking confirmation of regulatory treatment of any sale at this time.

CINGSA's capital expenditures for the years ended December 31, 2014 and 2013 are shown in the following table:

(US$ millions)	**2014**[(1)]	**2013**[(1)]
New business	0.3	6.6
System betterment and gas supply	0.1	
General plant	0.1	
Total	0.5	6.6

Notes:

(1) Numbers reflect SEMCO Energy's 65 percent interest.

2014 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 filed a true-up to reflect actual construction and operating costs. The RCA approved this true-up effective June 2014, which resulted in a reduction of rates to customers of approximately 6.1% in the annual levelized revenue requirement to be recouped in CINGSA's rates. This reduction in revenue will be largely offset by a similar reduction in interest expense as well as amortization of the interruptible storage service revenue deferred during the first two years of operations. 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 US$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 ENERGY BUSINESSES

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 2014 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 2014, SEMCO Energy's propane distribution served 5,700 residential and commercial customers compared with 5,827 residential and commercial customers in 2013. 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. For the year ended December 31, 2014, the net revenue for the Corporate segment was a loss of $12.1 million.

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 3.5 percent of the common shares of Alterra Power Corp. as at December 31, 2014.

AltaGas holds shares of Painted Pony Petroleum Ltd. In August 2014, AltaGas purchased 4,166,666 common shares for a total consideration of $50 million. Pursuant to the terms of the private placement, the common shares of Painted Pony Petroleum Ltd. subscribed for by AltaGas are subject to a contractual one-year hold period restriction. In December 2014, AltaGas purchased an additional 250,000 common shares of Painted Pony Petroleum Ltd. in a public offering for total consideration of $3.0 million. AltaGas held 4.4 percent of the common shares of Painted Pony Petroleum Ltd. as at December 31, 2014.

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 August 28, 2014, AltaGas closed a public offering of 9,027,500 Common Shares at a price of $51.00 per Common Share for total gross proceeds of approximately $460 million.

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. For the specific rights, privileges, restrictions and conditions attaching to the Series G Shares and Series H Shares, reference should be had to the prospectus supplement of AltaGas dated June 25, 2014 relating to the issue of the Series G Shares. Each such prospectus supplement has been filed with, and may be retrieved from, SEDAR at www.sedar.com.

On July 3, 2014, AltaGas closed a public offering of 8,000,000 Series G Shares at a price of $25.00 per Series G Share for aggregate gross proceeds of approximately $200 million.

Employees

At December 31, 2014 there were 1,694 individuals employed in AltaGas' businesses.

Gas	336
Power	136
Utilities	1,035
Corporate	187
Total	**1,694**

Directors and Officers

As at March 4, 2015: (i) the directors and executive officers of AltaGas Ltd., as a group, owned beneficially, directly or indirectly, or exercised control or direction over 2,963,923 of the outstanding Common Shares, or approximately 2.2 percent of the outstanding Common Shares; (ii) the directors and executive officers also had been granted, and had not yet exercised, share options to acquire an aggregate of 2,639,250 Common Shares; and (iii) 134,399,789 Common Shares were issued and outstanding.

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 4, 2015, 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**
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
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
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, 2014, are identified below:

Director	Audit Committee	Governance Committee	HRC Committee	EOH&S Committee
Catherine M. Best	✓			✓
David W. Cornhill				
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 AltaGas Services from 1994 to 2004.
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.
David M. Harris Calgary, Alberta, Canada President and Chief Operating Officer	President and Chief Operating Officer of AltaGas from January 2015. Chief Operating Officer of AltaGas from August 2013 to December 2014. 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	Executive Vice President of AltaGas from January 2015. Executive Vice President Corporate Development of AltaGas from December 2012 to December 2014. 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
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.

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. Mr. 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 2014 and 2013 were as follows:

Category of External Auditor Service Fee	2014	2013
Audit Fees	$1,550,272	$1,757,769
Audit-Related Fees(1)	$46,983	$34,163
Tax Fees(2)	$23,903	$52,919
All Other Fees(3)	$546,811	$339,518
TOTAL	$2,167,968	$2,184,369

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 the review of unconsolidated financial statements for AIJVLP and Petrogas and registration costs for the Canadian Public Accountability Board.

(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, advisory services for systems implementation, and other services required for AltaGas public finance activities.

RISK FACTORS

A security holder of AltaGas should consider carefully the risk factors set out below. In addition, prospective security holders of AltaGas 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.

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, NGL, LNG and LPG 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

There can be no assurance that AltaGas will be able to obtain or maintain adequate insurance 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.

Internal Credit Risk

Credit ratings affect AltaGas' ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of AltaGas to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on AltaGas' credit ratings. A reduction in the current rating on AltaGas' debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings or a negative change in AltaGas' ratings outlook could adversely affect AltaGas' cost of financing and its access to sources of liquidity and capital. Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to AltaGas' 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. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

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, LNG, LPG 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, NGLs, LNG and LPG, 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, in both North American markets and, with respect to the LNG and LPG export business, offshore markets. North American and, with respect to the LNG and LPG export business, offshore markets commodity supply and demand is affected by a number of factors including, but not limited to, the amount of the commodity available to specific market areas either from the well head or from storage facilities, prevailing weather patterns, the U.S., Canadian and Asian economies, the occurrence of natural disasters and pipeline restrictions. The fluctuations in commodity prices are beyond AltaGas' control and accordingly, could have a material adverse effect on AltaGas' business, financial condition and cash flow.

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' revenue from sales of power in other jurisdictions may become subject to similar factors upon termination of existing EPAs, PPAs and REPAs.

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 and accordingly, could have a material adverse effect on AltaGas' business, financial condition and cash flow.

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, and the export and import of LNG and LPG may be subject to regulatory approvals. 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 or the LNG and LPG export business. 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 has credit risk relating to numerous industrial, commercial and institutional counterparties.

Foreign Exchange Risk

AltaGas is exposed to foreign exchange risk through its investments in the United States, and may in the future be exposed to foreign exchange risk in the LNG and LPG export business. 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 Harmattan can be claimed by the original Harmattan 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 - Environment

Management has identified environmental issues associated with the prior activities of Harmattan. There are indications of significant groundwater and soil contamination resulting from Harmattan's prior activities. There is a risk that the costs of addressing these environmental issues could be significant.

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, LNG, LPG 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, LNG, LPG 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 no 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. In particular, pursuant to the *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* (the "CO_2 Regulations") promulgated under the *Canadian Environmental Protection Act, 1999* (the "Canadian EPA"), the Canadian federal government has established a regime for the reduction of carbon dioxide emissions resulting from the production of electricity by means of thermal energy using coal as a fuel. Certain provisions of the CO_2 Regulations came into force on January 1, 2013 and required the registration of existing coal-fired electricity generation units by February 1, 2013. Those aspects of the CO_2 Regulations establishing a performance standard for the intensity of CO_2 emissions from regulated units and exceptions therefrom based on the substitution of units and in relation to emergencies and units integrated with carbon capture and storage systems are scheduled to come into force on July 1, 2015. Finally, the provisions of the CO_2 Regulations respecting emission intensity limits on units are scheduled to come into force on January 1, 2030.

Regulated entities will be subject to enforcement and compliance requirements and penalties as specified under the Canadian EPA.

Canadian Provincial GHG Regulations

<u>Alberta</u>

On July 1, 2007, the *Specified Gas Emitters Regulation* under the *Climate Change and Emissions Management Act* (Alberta) took effect. The regulation applies to large emitter facilities with direct emissions totalling 100,000 tonnes or more 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, commencing with their 4^{th} year of commercial operations.

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. The amount of money that a person responsible must contribute to the Climate Change and

Emissions Management Fund to obtain one fund credit equal to a one tonne reduction in emissions will be set by Order of the responsible minister.

Both the Harmattan facility and the Sundance B plant that is the subject of the Sundance B PPAs are considered large emitters under Alberta's *Specified Gas Emitters Regulation*, since each facility exceeded 100,000 tonnes of greenhouse gas emissions in 2014.

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 Partnership, and at the cost of ASTC Partnership, 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 2014 is approximately $5.8 million.

British Columbia

The *Greenhouse Gas Reduction (Cap and Trade) Act* (British Columbia) was passed in May 2008 and authorizes hard caps on greenhouse gas emissions, making B.C. the first Canadian province to introduce such legislation. It provided authority for the *Reporting Regulation* (enacted in November 2009) and, when ultimately promulgated, will provide the authority for the proposed *Offsets Regulation* and *Emissions Trading Regulation*. The legislation provides the statutory basis for setting up a market-based cap and trade framework to reduce greenhouse gas emissions from large emitters operating in the province. Parts of the legislation were brought into force when the *Reporting Regulation* was enacted, while the remaining portions will be brought into force by regulation as the relevant regulations are developed.

AltaGas' Blair Creek processing facility and Younger Extraction Plant are both subject to the reporting obligations imposed by the *Reporting Regulation* and are in compliance therewith.

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. However, the U.S. Environmental Protection Agency has announced its intention to take administrative action targeting the natural gas transmission industry to reduce emissions of methane and volatile organic compounds.

Manufactured Gas Plants

SEMCO Gas' 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 Gas may be responsible for the investigation and remediation of environmental conditions at currently owned or leased sites, formerly owned, leased, operated or used sites as well as sites of historical off-site waste disposal by SEMCO Gas or its predecessors. SEMCO Gas 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 Gas' facilities or the land on which such facilities are located, regardless of whether SEMCO Gas owns or leases the facility, and regardless of whether such environmental conditions were created by SEMCO Gas or by a prior owner or tenant, or by a third party or a neighboring facility whose operations may have affected the SEMCO Gas' 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 Gas is responsible for the investigation and remediation of two sites in Michigan where MGPs were formerly located. SEMCO Gas's predecessors operated MGP facilities at these two sites. In August 2014, a settlement was reached related to a third MGP site previously owned by SEMCO Gas.

Given the nature of the past operations conducted by SEMCO Gas and others at SEMCO Gas' 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 also may give rise to environmental liabilities which may be material.

Compliance with the requirements and terms and conditions of the environmental licenses, permits and other approvals that are required for the operation of SEMCO Gas' business may cause SEMCO Gas to incur substantial capital costs and operating expenses and may impose restrictions or limitations on the operation of SEMCO Gas' business, all of which could be substantial. Environmental, health and safety regulations may also require SEMCO Gas 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, Series E Shares and Series G 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 2012, 2013 and 2014.The table also summarizes the cash dividends paid by AltaGas in 2012, 2013 and 2014 on the Series A Shares, issued in August 2010, the Series C Shares, issued in June 2012, the Series E Shares, issued in December 2013, and the Series G Shares, issued in July 2014.

Dollars per share	**2014**	**2013**	**2012**
Common Shares	1.6700	1.4850	1.3950
Series A Shares	1.2500	1.2500	1.2500
Series C Shares(1)	1.1000	1.1000	0.6223
Series E Shares	1.3074	-	-
Series G Shares	0.5865	-	-

(1) Amounts disclosed are in US dollars.

DIVIDEND REINVESTMENT AND OPTIONAL COMMON SHARE PURCHASE PLAN

AltaGas has adopted the Plan for holders of Common Shares.

The Plan, as may be amended from time to time, provides eligible shareholders 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). Shareholders resident outside of Canada are not entitled to participate in the Plan.

MARKET FOR SECURITIES

The following chart provides the reported high and low trading prices and volume of Common Shares, traded on the TSX under the symbol ALA, traded by month from January to December 2014 as reported by the TSX:

Month	High	Low	Volume Traded
January	41.86	40.07	5,160,771
February	42.88	40.31	4,095,353
March	45.45	41.84	5,023,992
April	47.71	45.23	4,468,293
May	49.89	46.93	5,331,796
June	49.85	48.01	4,242,113
July	50.40	47.75	4,737,420
August	53.06	47.87	9,308,760
September	52.57	46.21	10,056,061
October	48.47	39.10	11,497,288
November	46.40	42.16	7,790,539
December	43.63	36.19	13,263,324

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 Series A Shares from January to December 2014 as reported by the TSX:

Month	High	Low	Volume Traded
January	25.58	25.00	112,949
February	25.24	24.45	130,251
March	25.37	24.51	141,044
April	25.62	25.07	90,161
May	26.14	25.17	247,582
June	25.42	24.86	110,119
July	25.66	25.05	62,905
August	25.52	25.07	59,507
September	25.49	25.01	90,821
October	25.82	25.15	270,253
November	25.55	25.16	40,318
December	26.12	24.51	145,732

Series C Shares are traded on the TSX under the symbol ALA.PR.U. The following table sets forth the monthly price range (in US dollars) and volume traded for Series C Shares from January to December 2014 as reported by the TSX:

Month	High	Low	Volume Traded
January	25.02	24.75	159,947
February	25.04	24.78	155,932
March	25.30	24.90	170,813
April	25.69	25.05	198,587
May	25.96	25.41	132,399
June	25.75	25.27	159,090
July	25.91	25.30	87,381
August	26.03	25.50	78,137
September	26.11	25.50	176,398
October	25.95	25.30	123,662
November	25.85	25.50	93,873
December	25.68	24.70	182,044

Series E Shares are traded on the TSX under the symbol ALA.PR.E. The following table sets forth the monthly price range and volume traded for Series E Shares from January to December 2014 as reported by the TSX:

Month	High	Low	Volume Traded
January	25.61	25.30	720,108
February	25.67	25.26	187,923
March	25.91	25.55	159,938
April	26.12	25.51	146,512
May	26.73	25.61	186,676
June	26.01	25.43	161,264
July	25.95	25.75	68,481
August	26.31	25.80	54,201
September	26.30	25.82	434,604
October	26.25	26.00	529,887
November	26.71	26.25	41,038
December	26.68	25.66	171,327

Series G Shares began trading on the TSX on July 3, 2014 under the symbol ALA.PR.G. The following table sets forth the monthly price range and volume traded for Series G Shares for the period of July 3, 2014 to December 31, 2014 as reported by the TSX:

Month	High	Low	Volume Traded
July	25.57	25.05	1,457,609
August	25.90	25.37	171,357
September	25.85	25.32	173,720
October	25.98	25.53	320,221
November	26.08	25.88	60,568
December	26.20	25.20	367,748

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following table summarizes selected AltaGas financial information for the last three financial years (amounts may not add due to rounding):

Year ended and as at December 31 *($ millions unless otherwise indicated)*	**2014**	**2013**	**2012**
Revenue			
Gas	1,178.8	1,019.8	844.0
Power	388.0	300.4	216.1
Utilities	1,076.9	894.4	437.6
Corporate	4.7	(9.2)	22.1
Intersegment Eliminations	(242.5)	(162.5)	(70.2)
	2,405.8	2,042.9	1,449.7
Net revenue			
Gas	424.7	368.9	322.0
Power	184.5	177.1	109.0
Utilities	429.7	434.7	212.7
Corporate	(12.1)	(14.2)	22.6
Intersegment Elimination	(7.8)	(6.3)	(2.0)
	1,018.9	960.2	664.4
EBITDA	563.6	538.9	319.3
Net income	95.6	181.5	101.8
- per share (basic)	0.75	1.56	1.07
Funds from operations	470.9	400.3	254.6
Total assets	8,413.4	7,284.2	5,932.4
Total debt	3,336.4	3,246.2	2,702.3

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-3 (High) and DBRS rating of Pfd-3. AltaGas' Preferred Shares continue to have an S&P rating of P-3 (High) 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 under its Canadian preferred share rating scale and a P-3 (High) rating directly corresponds with a BB+ rating under its global preferred rating scale. The Canadian preferred share rating scale is fully determined by the global preferred rating scale and there are no additional analytical criteria associated with the determination of ratings on the Canadian preferred share rating scale. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non-payment than other speculative issues. However, it faces major 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, 2018. 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; and
- 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.

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. SW, 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, share options, and interests of insiders in material transactions, where applicable, is contained in AltaGas' Management Information Circular dated March 9, 2015, which is expected to be filed on or about March 20, 2015 in connection with the Annual General Meeting of shareholders to be held April 30, 2015.

Additional financial information is contained in AltaGas' consolidated financial statements for the year ended December 31, 2014 and management's discussion and analysis contained in the 2014 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 SW, Calgary, Alberta T2P 3S8, Tel: 1-800-564-6253.

The registrar and trustee for AltaGas' MTNs is Computershare Trust Company of Canada, 710, 530 - 8th Avenue SW, 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, 2014.

SCHEDULE A: AUDIT COMMITTEE MANDATE

I. Constitution

The Board of Directors of AltaGas Ltd. ("AltaGas" or the "Corporation") 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 Corporation,
- Independent, and
- Financially literate.

No Member of the Committee shall be an officer or employee of the Corporation 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 Corporation. 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 Corporation. 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 permits 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 Corporation 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 the Audit Committee.

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

VI. Relations with Management

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

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

VII. Committee Timetable

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

AltaGas Ltd.
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