ALTAGAS LTD.

Annual Information Form

For the year ended December 31, 2016

Dated: February 22, 2017

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GENERAL INFORMATION

Unless otherwise noted, the information contained in this Annual Information Form (AIF) is stated as at December 31, 2016 and all dollar amounts in this AIF are in Canadian dollars. Financial information is presented in accordance with United States generally accepted accounting principles. For an explanation of certain terms and abbreviations used in this AIF see the “Glossary” of this AIF.

FORWARD-LOOKING INFORMATION

This AIF contains forward-looking statements. When used in this AIF the words "may", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "estimate", "focus", "strive", "forecast", "expect", "project", "target", "potential" and similar expressions suggesting future events or future performance, as they relate to the Corporation, are intended to identify forward-looking statements. In particular, this AIF 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’ expectations of growth in natural gas supply and demand for clean energy; prospects for growth; the potential for growth through acquisition and development of energy infrastructure; and AltaGas’ ability to maximize profitability of its assets and to add complimentary services to its existing business segments. In addition, forward-looking statements are set forth under the following headings and sub-headings:

- "AltaGas’ Vision and Objective", including AltaGas’ belief that investing in low-risk, long-life energy assets will generate superior economic returns; AltaGas’ expectations regarding sources of utility like returns and long life cash flows; AltaGas’ expectations regarding diversification including impact on earnings and cash flow and reduction to exposure to commodity market volatility; expectations that expansion of business through acquisitions and organic growth will support dividend and capital growth; and expectations regarding the abundant supply of natural gas in North America and the increasing global demand for clean energy and the opportunities those will bring for sustained growth across all of AltaGas’ business segments.

- "AltaGas’ Strategy", including expectations that AltaGas will acquire or build gas gathering and processing infrastructure from, or on behalf of, producers wishing to redeploy capital to exploration and production activities rather than to non-core activities such as midstream services; AltaGas’ potential to move natural gas and NGLs to key markets including Asia, AltaGas’ ability to provide a fully integrated midstream service offering to its customers across the energy value chain; expectations as to AltaGas’ position to deliver higher netbacks to producers for NGL by establishing a western energy hub in northeast British Columbia, through its ownership interest in Petrogas and the Ferndale Terminal and the development of the Ridley Island Propane Export Terminal; AltaGas’ ability to focus on developing and operating larger gas infrastructure projects and AltaGas’ cost of doing so; expectations with respect to the combined enterprise; expectations with respect to WGL’s midstream business and expected operational date of the Cove Point LNG export facility; expectations for the increased use of natural gas, providing opportunities for AltaGas to invest in and optimize assets; expectations regarding the decrease in U.S. demand for import of gas, NGLs and crude oil and impact that has on netbacks for Canadian energy sector; AltaGas’ belief that energy market diversification is critical for Canadian producers; expectations regarding the supply of NGL and natural gas reserves, demands from Asia for such products and opportunities such supply and demand presents for investing in infrastructure outside of North America; expectations that AltaGas is uniquely positioned to provide a competitive service to producers; AltaGas’ experience and ability to operate LPG export terminals; AltaGas’ ability to provide multiple outlets for producers to access the highest value markets; expectations that access to Asian markets provides diversity to producers; expectations relating to AltaGas’ access to Asian markets, including through AltaGas’ relationship with Idemitsu; expectations that natural gas-fired power generation will provide critical load balancing across North America; expectations regarding the decommissioning of nuclear and coal-fired generation and expected timeline for decommissioning; expectations that renewable power and natural gas-fired power generation will replace nuclear and coal-fired power generation and that AltaGas is in a position to take advantage of such replacement opportunities; expectations for opportunities arising from increased demand in North America for clean sources of power and that AltaGas is in position to take advantage of such opportunities; expectations regarding expansion and re-contracting opportunities and that AltaGas is in a position to take advantage of such opportunities including in northern California as a result of the acquisition of the San Joaquin Facilities and Ripon and in southern California as a result of the suitability of the Pomona site for future battery storage or repowering optionality provided by the location of the Blythe Energy Center and potential expansion phases; expectations with respect to the expansion of Blythe Energy Center; expectations of further development and expansion of power assets; expectations for rate base growth in the utilities segment including through the execution of strategic utility acquisitions, the addition of customers and improvement and upgrade of infrastructure; expectations for growth in the utilities segment as sources of such growth including expansion of and investment in existing distribution systems, acquisition of new franchises, fuel switching and development of natural gas storage opportunities; expectations as to AltaGas' ability to maintain financial strength and flexibility, sufficient liquidity, an investment grade credit rating and ready access to capital markets; and expectations with respect to in-house construction expertise and competitive advantages of such expertise.

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

- "General Development of AltaGas' Business" under the following sub-headings:
  - "Recent Developments", expectations with respect to the WGL Acquisition including the expected closing date, ability to obtain, and timeline for obtaining, regulatory and other approvals, the aggregate cash consideration including the anticipated sources of financing thereof and anticipated indebtedness under the Bridge Facility, planned asset divestitures, anticipated benefits of the WGL Acquisition including the portfolio of assets of the combined entity, nature, number, value and timing of growth and investment opportunities available to AltaGas, the quality and growth potential of the assets, the strategic focus of the business, the combined rate base and rate base growth, the ability of the combined entity to target higher growth markets, high growth franchise areas, and other growth markets, expected timing and capital expenditures for certain WGL projects and expected capital investment by business segment; expectations for the Cove Point LNG export facility including anticipated completion timing, the stability of cash flows and of AltaGas' business, the growth potential available to AltaGas in the Midstream business, clean energy, natural gas generation and retail energy services, the significance and growth potential and expectations for growth in the Montney and Marcellus/Utica formation.
  - "Development of the Gas Business", including expectations with respect to the Alton Natural Gas Storage Facility including expected storage capacity, construction timeline and storage in service date; expectations relating to the North Pine Facility and North Pine Pipelines including, construction plans, phased development, connection capability to rail, existing AltaGas infrastructure, the proposed Ridley Island Propane Export Terminal and Alaska highway truck terminal, facility specifications, location, handling capability, service area, cost, product mix, timeline for site preparation and commercial operation and expectations regarding Painted Pony's gas volumes, commitment and contract; expectations with respect to the Townsend Facility including AltaGas' ability to increase the size of the Townsend Facility, to retrofit to deep cut facility and timing of retrofit; expectations with respect to the Townsend Phase 2 and related infrastructure including design specifications, phased development or development in trains, location, capacity, cost, commitment, take or pay arrangements and expected gas volumes from Painted Pony, compression requirements, connection capability to North Pine Facility, plans for transport including new NGL pipelines and expected timeline for commercial operations; expectations with respect to the proposed Ridley Island Propane Export Terminal including costs, propane transport capability, locational benefits, initial shipment capacity, connection capability, quality of transport options, sources of propane supply, AltaGas' ability to construct new plants and develop new projects, expectations regarding tolling arrangements, expectations of being the first propane export terminal off the west coast of British Columbia, sale and purchase of liquefied petroleum gas from the terminal, entering into a multi-year agreement with Astomos, relations with First Nations and Astomos, potential for third party investment, offtake opportunities, expectations of serving growing demand in Asia and offering new markets to producers and timing of construction and commercial operations.
  - "Development of the Power Business", including expectations in regards to Blythe II and Blythe III, including potential for expansion of generation capacity in California, resulting contracting opportunities including the nature and type of contracting opportunities available and the potential to triple the existing generation capacity in the vicinity of the Blythe Energy Center; expectations regarding the low-risk nature of cash flows generated by the PPAs for the San Joaquin Facilities and expectations regarding the installment payments to be made under the settlement agreement relating to termination of the Sundance B PPAs.

- "Development of the Utilities Business", including in respect of expectations regarding annual capital spend for, and revenue from SEMCO Gas' MRP; expectations regarding ENSTAR's rate case including anticipated annual base rate, revenue increase and decision date; and expectations relating to SEMCO Gas' MCP including timeline for MPSC approval, construction and in-service date, cost, location, connection capability to existing pipelines and gas supply opportunities.

- "Business of the Corporation" under the following sub-headings:

  - "Gas Business – Extraction", including the expected completion date of decommissioning of the Empress ATCO extraction plant; in respect of the impact of commodity prices or operating costs on NGL extraction; expectations for extraction rights being retained by extraction facility owners; expectations regarding status of site development for the North Pine Facility and North Pine Pipeline and target commercial on-stream date; AltaGas' belief that the extraction assets are well-positioned and strategically located; the ability of such assets to compete in the NGL industry; and in respect of Harmattan being a significant service provider and well-positioned as a high-volume, low-cost processing facility with opportunities to consolidate and increase asset utilization and profitability.

  - "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 including expectations regarding the competitive advantages from the development of LPG export capacity; AltaGas' belief with respect to its operational skills, that it would be a preferred business partner for many exploration and production companies and the expected closing date for the purchase of the EDS and JFP NGL pipelines.

  - "Gas Business – Energy Services", including low-risk nature of opportunities in energy services business.

  - "Gas Business – Energy Export", including expectations regarding the Ridley Island Propane Export Terminal (see "Development of the Gas Business" above); that AltaGas will pursue LPG export opportunities through its ownership interest in Petrogas and AltaGas' views with respect to the location of Petrogas' major terminal and owned and leased storage facilities.

  - "Power Business", including expectations for growth driven by renewable energy projects and gas-fired generation opportunities and the significance of such growth portfolio; expectations for development in the coming years and targeted locations for such development; expectations regarding market access optionality, connection and transmission capability for the Blythe Energy Center and capacity for future load growth; potential for expansion of generation capacity in California, resulting contracting opportunities including the nature and type of contracting opportunities available and the potential to triple the existing generation capacity in the vicinity of the Blythe Energy Center; expectations in regards to Pomona including the strategic location of Pomona, suitability of the Pomona site for incremental development opportunities for additional energy storage or gas-fired generation, ability to repower, increase capacity and reconfigure Pomona and expected timeline for completion of the application review process and permitting; expectations relating to the AltaGas Pomona Energy Storage Project including AltaGas' ability to operate the facility, expected energy storage capacity and available resource adequacy, battery run time, expectations regarding resource adequacy payments and AltaGas' ability to earn additional revenue from energy from batteries and impact successful completion has on AltaGas; and the intentions of BMWLP in respect of green attributes and RECs.

  - "Utilities Business", including expectations regarding PNG, ENSTAR and CINGSA rate cases including filing timeline, expected test years, revenue increases and decision date; expectations regarding timeline for implementation of rates for AUI under the second generation PBR plan and term of PBR plan; expectations regarding contracting by Heritage Gas for gas supply for winter heating season; expectations regarding Alton Natural Gas Storage Facility including status of construction and expected in service date, ability to provide to Heritage Gas security and reliability of gas supply and to reduce price volatility for Heritage Gas; expected in service date for the Atlantic Bridge Project; expectations regarding Heritage Gas' Customer Retention Program including, expectations of customer retention, natural gas and propane prices and the duration of the program; expectations of alternative supply sources for Heritage Gas, the decline in natural gas supply from the Sable Offshore Energy project, rate of decline and expected end date of reserves; PNG's ability to obtain new customers for released capacity on the Western System; expectations on timeline for Inuvik Gas to transition ownership; expectations regarding SEMCO Gas' MCP (see "Development of the Utilities Business" above); SEMCO Gas' monitoring ability of the MGP sites it is responsible for; the ability of Cook Inlet production to meet ENSTAR supply needs; the possibility that prospective Alaska LNG exports could meet ENSTAR supply needs; expectations regarding the working capacity of the CINGSA Storage Facility; and expectations regarding stage of appeal process in regards to CINGSA found gas decision.

- "Risk Factors" under the following sub-headings:
  - "Capital Markets", including in relation to AltaGas' expectations regarding sources of funds for capital expenditures and AltaGas' belief that it has sufficient funds to fund its projected capital expenditures;
  - "Aboriginal Lands and Rights Claims" including AltaGas' ability to conclude agreements with Aboriginal communities in respect of projects under development;
  - "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
  - "Health and Safety", including AltaGas' ability to continue to actively work with industry groups and communities to improve safety.
- "Environmental Regulations" under the following sub-headings:
  - "Canadian Federal Air and GHG Regulations", including in respect of the ability of the utilities business to flow through carbon tax to its customers and the increase in the number of facilities subject to reporting requirements under the Federal Greenhouse Gas Reporting Programme; and
  - "California GHG Regulations" in respect of AltaGas' expectation regarding the demand in California for highly responsive generation assets and energy storage assets and AltaGas' belief that it is well positioned to take advantage of such opportunities.

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, aboriginal or regulatory developments, changes in tax legislation, fluctuations in commodity prices, interest or foreign exchange rates, access to capital markets, general economic conditions, changes in the political environment, changes to environmental and other laws and regulations, cost for labour, equipment and materials and the other factors discussed under the heading "Risk Factors" in this AIF.

Many factors could cause AltaGas' or any particular business segment's actual results, performance or achievements to vary from those described in this AIF, 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 AIF as intended, planned, anticipated, believed, sought, proposed, estimated or expected, and such forward-looking statements included in this AIF, should not be unduly relied upon. Such statements speak only as of the date of this AIF. 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 AIF are expressly qualified by these cautionary statements.

Financial outlook information contained in this AIF about prospective results of operations, financial position or cash flow 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 AIF should not be used for purposes other than for which it is disclosed herein.

GLOSSARY

Unless the context otherwise requires, terms used in this AIF have the following meanings and references to agreements include any amendments, restatements, modifications or supplements in effect as of the date hereof:

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

"**AIF**" means this Annual Information Form;

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

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

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

"**Alton Natural Gas Storage Facility**" means the underground gas storage facility and associated pipelines located near Truro, Nova Scotia that is currently under construction and owned by AltaGas' indirect wholly-owned subsidiary Alton Natural Gas Storage L.P.;

"**Astomos**" means Astomos Energy Corporation;

"**Atlantic Bridge Project**" means the construction of additional pipeline and related facilities infrastructure by Spectra Energy to provide additional capacity on its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems to move natural gas into New England and to specific end use markets in the Canadian Maritime provinces targeting an initial in-service date in November 2017;

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

"**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 billion cubic feet or 1,000,000 Mcf of natural gas;

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

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

"**BCOGC**" means British Columbia Oil and Gas Commission;

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

"**Blair Creek Facility**" means the Blair Creek Processing Facility located approximately 140 km northwest of Fort St. John, British Columbia, owned by AltaGas' indirect wholly-owned subsidiary AltaGas Northwest Processing Limited Partnership;

"**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 site for the development of an approximately 500 MW power generation facility, 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 to Blythe II;

"**BMWLP**" means Bear Mountain Wind Limited Partnership, a wholly owned subsidiary of AltaGas Ltd.;

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

"**Bridge Facility**" means the US$3.1 billion bridge facility to be provided by a syndicate of lenders, including JPMorgan Chase Bank, N.A., The Toronto-Dominion Bank and Royal Bank of Canada on substantially the terms set forth in the Debt Commitment Letter;

"**Burdensome Condition**" means any undertakings, terms, conditions, liabilities, obligations, commitments, sanctions or other measures (including any Remedial Action) that would have or would reasonably be expected to have, individually or in the aggregate, a material adverse effect on the financial condition, assets, liabilities, businesses or results of operations of (a) WGL and its subsidiaries, taken as a whole, or (b) AltaGas and its subsidiaries, taken as a whole and determined after giving effect to the transactions contemplated by the Merger Agreement; provided, however, that any such undertakings, terms, conditions, liabilities, obligations, commitments, sanctions or other measures shall not constitute or be taken into account in determining whether there has been or is such a material adverse effect to the extent such undertakings, terms, conditions, liabilities, obligations, commitments, sanctions or other measures are expressly set forth in the post-merger commitments of AltaGas set forth in the Merger Agreement;

"**Brush II**" means the 70 MW gas-fired generation facility in Colorado, owned by AltaGas' indirect wholly-owned subsidiary AltaGas Brush Energy Inc.;

"**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;

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

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

"**Concurrent Private Placement**" has the meaning given to it under "Capital Structure – Description of Capital Structure – Subscription Receipts";

"**Consortium**" means the group consisting of AltaGas Idemitsu Joint Venture #2 Limited Partnership, EXMAR NV and EDFT formed to develop the DC 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;

"**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;

"**Customer Retention Program**" has the meaning given to it under "Business of the Corporation – Heritage Gas - Material Regulatory Developments and Applications";

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

"**DC LNG Project**" means the proposed floating LNG project that was being developed by the Consortium on the west bank of the Douglas Channel in Kitimat, British Columbia;

"**Debt Commitment Letter**" means the Debt Commitment Letter, dated as of January 25, 2017, by and among AltaGas, JPMorgan Chase Bank, N.A., The Toronto-Dominion Bank and Royal Bank of Canada, as amended, restated, supplemented, replaced or otherwise modified from time to time;

"**Dekatherm**" means 10 Therms;

"**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;

"**Dividend Equivalent Payments**" means payments per Subscription Receipt equal to the per Common Share cash dividends, if any, declared by AltaGas on the Common Shares in respect of all record dates for such dividends occurring from February 3, 2017 to, but excluding, the last day on which the Subscription Receipts remain outstanding, to be paid to holders of Subscription Receipts concurrently with the payment date of each such dividend on AltaGas' outstanding Common Shares, paid first out of any interest credited or received on the Escrowed Funds and then as a refund of a portion of the offering price of $31.00 per Subscription Receipts;

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

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

"**ESA**" means Energy Storage Resource Adequacy Purchase Agreement;

"**Escrow Release Condition**" means the parties to the Merger Agreement are able to complete the WGL Acquisition in all material respects in accordance with the terms of the Merger Agreement, without amendment or waiver materially adverse to AltaGas, unless the consent of co-lead underwriters of the Offering is given to such amendment or waiver (such consent not to be unreasonably withheld), but for the payment of the purchase price, and AltaGas has available to it all other funds required to complete the WGL Acquisition; provided that the Escrow Release Condition may, if the foregoing conditions are met, at the election of AltaGas, occur up to six business days prior to the scheduled closing date;

"**Escrow Release Notice and Direction**" means the notice to be provided to the subscription receipt agent, executed by AltaGas and the co-lead underwriters on behalf of the underwriters of the Offering, certifying that the Escrow Release Condition has been satisfied;

"**Escrowed Funds**" means, collectively, the Proceeds, earned interest thereon and any investments acquired or made from time to time with such funds, as such funds may be reduced upon payment of Dividend Equivalent Payments or other amounts payable under the Subscription Receipt Agreement from the Proceeds or earned interest;

"**FERC**" means the United States Federal Energy Regulatory Commission;

"**Ferndale Terminal**" means the storage, distribution and export facility for bulk shipments of propane, butane and iso-butane located on the west 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 facilities in northwest British Columbia that forms part of the Northwest Hydro Facilities;

"**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;

"**GHG**" means greenhouse gas;

"**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 Northwest Processing Limited Partnership;

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

"**Hampshire**" means Hampshire Gas Company, a subsidiary of WGL that provides regulated interstate natural gas storage services to Washington Gas under a FERC approved interstate storage service tariff;

"**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;

"**HSR Act**" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended;

"**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 facility, one of the three run-of-river hydroelectric facilities in northwest British Columbia that forms part of the Northwest Hydro Facilities;

"**MCP**" means the Marquette Connector Pipeline, the proposed new pipeline to be constructed, owned and operated by SEMCO Gas that will connect the Great Lakes Gas Transmission pipeline to the Northern Natural Gas pipeline in Marquette, Michigan;

"**MDth**" means millions of Dekatherms;

"**Merger Agreement**" means the agreement and plan of merger dated as of January 25, 2017 among AltaGas, Merger Sub and WGL;

"**Merger Sub**" means Wrangler Inc., a Virginia corporation and an indirect wholly-owned subsidiary of AltaGas;

"**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;

"**MRP**" means Main Replacement Program;

"**MTN**" means medium term notes issued from time to time under the amended and restated trust indenture dated July 1, 2010 between AltaGas and Computershare Trust Company of Canada, as further amended, restated, supplemented or otherwise modified from time to time;

"**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.;

"**North Pine Facility**" means a NGL separation train capable of processing up to 10,000 Bbls/d of propane plus NGL mix, located approximately 40 km northwest of Fort St. John, British Columbia;

"**North Pine Pipelines**" means two eight inch diameter NGL supply pipelines, each approximately 40 km in length, which are to run from the existing Alaska Highway truck terminal to the North Pine Facility;

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

"**Northwest Hydro Facilities**" means the three run-of-river hydroelectric facilities 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;

"**NYSDEC**" means the New York State Department of Environmental Conservation;

"**Offering**" has the meaning given to it under "Capital Structure – Description of Capital Structure – Subscription Receipts";

"**Painted Pony**" means Painted Pony Petroleum Ltd.;

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

"**PG&E**" means Pacific Gas & Electric Company;

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

"**Petrogas**" means Petrogas Energy Corp., a privately-held leading North American integrated midstream company in which AIJVLP has a two-third ownership interest;

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

"**Plan**" means the Premium Dividend™, Dividend Reinvestment and Optional Cash 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 AESO for (i) exchanges of electric energy, and (ii) financial settlement for the exchange of electric energy;

"**Pomona**" means the 44.5 MW gas-fired generation facility located in Pomona, California, owned by AltaGas' indirect wholly-owned subsidiary AltaGas Pomona Energy Inc.;

"**Pomona Energy Storage Facility**" means the 20 MW lithium ion battery storage facility in Pomona, California, owned by AltaGas' indirect wholly-owned subsidiary AltaGas Pomona Energy Storage Inc.;

"**PPA**" means power purchase agreement;

"**Preferred Shares**" means the preferred shares of AltaGas Ltd. 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, Series H Shares, Series I Shares, Series J Shares, Series K Shares and Series L Shares;

"**Proceeds**" means an amount equal to: (a) the offering price of $31.00 per Subscription Receipt multiplied by the total number of Subscription Receipts issued pursuant to the Offering, less 50 percent of the underwriters' fee; and (b) the offering price of $31.00 per Subscription Receipt multiplied by the total number of Subscription Receipts issued pursuant to the Concurrent Private Placement (after deducting the capital commitment fee payable to the private placement subscriber);

"**PRPA**" means Prince Rupert Port Authority;

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

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

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

"**Regulatory Approvals**" means (i) any consents required by the Public Service Commission of the District of Columbia, The Maryland Public Service Commission and The Commonwealth of Virginia State Corporation Commission; (ii) the approval of the Committee on Foreign Investment in the United States; and (iii) any consents required by FERC, in respect of the transactions contemplated by the Merger Agreement;

"**Remedial Action**" means committing to and effecting, by consent decree, hold separate orders, trust, or otherwise, (a) the sale, license, holding separate or other disposition of assets or businesses of AltaGas or WGL or any of their respective subsidiaries, (b) terminating, relinquishing, modifying or waiving existing relationships, ventures, contractual rights, obligations or other arrangements of AltaGas or WGL or any of their respective subsidiaries and (c) creating any relationships, ventures, contractual rights, obligations or other arrangements of AltaGas or WGL or any of their respective subsidiaries;

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

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

"**Ridley Island Propane Export Terminal**" means the propane export terminal being constructed by AltaGas to ship up to 1.2 million tonnes of propane per annum and to be located on a portion of land leased by Ridley Terminals Inc. from the PRPA, located on Ridley Island, near Prince Rupert, British Columbia;

"**Ridley Terminals**" means Ridley Terminals Inc.;

™ Denotes trademark of Canaccord Genuity Corp

"**Ripon**" means the 49.5 MW gas-fired generation facility in Ripon, California, owned by AltaGas' indirect wholly-owned subsidiary AltaGas Ripon Energy Inc.;

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

"**San Joaquin Facilities**" means the 330 MW Tracy, the 97 MW Hanford and the 96 MW Henrietta gas-fired generation facilities located in northern California, owned by AltaGas' indirect wholly-owned subsidiary AltaGas San Joaquin Energy Inc.;

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

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

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

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

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

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

"**Series C Shares**" means the cumulative redeemable 5-year fixed rate reset preferred shares, Series C, of AltaGas Ltd. (US dollar);

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

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

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

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

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

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

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

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

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

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

"**Shareholders**" mean the holders of Common Shares;

"**Subscription Receipts**" means the subscription receipts of AltaGas Ltd., each of which entitles the holder thereof to receive, without payment of additional consideration or further action, one Common Share upon the closing of the WGL Acquisition;

"**Subscription Receipt Agreement**" means the subscription receipt agreement dated February 3, 2017 among AltaGas, the co-lead underwriters of the Offering and Computershare Trust Company of Canada, as subscription receipt agent, governing the terms of the Subscription Receipts;

"**Sundance B**" means unit 3 and unit 4 of the coal-fired Sundance plant owned by TransAlta Generation Partnership located approximately 70 km west of Edmonton, Alberta;

"**Sundance B PPAs**" means the former power purchase arrangements of ASTC Power Partnership with respect to Sundance B;

"**Termination Event**" means any of: (a) if an Escrow Release Notice and Direction has not been delivered prior to 5:00 p.m. (Calgary time) on September 4, 2018 or if an Escrow Release Notice and Direction has been delivered but the Escrowed Funds are subsequently returned to the subscription receipt agent pursuant to the Subscription Receipt Agreement; (b) the termination of the Merger Agreement; (c) delivery by AltaGas to the co-lead underwriters, on behalf of the underwriters of the Offering, and the subscription receipt agent, of a notice executed by AltaGas indicating that AltaGas does not intend to proceed with the WGL Acquisition; or (d) the public announcement by AltaGas that it does not intend to proceed with the WGL Acquisition;

"**Termination Time**" means the time of occurrence of the earliest Termination Event;

"**Therm**" is a natural gas unit of measurement that includes a standard measure for heating value. A therm of gas contains 100,000 British thermal units of heat, or the energy equivalent of burning approximately 100 cubic feet of natural gas under normal conditions. Ten million therms equal approximately one billion cubic feet of natural gas. One Mcf equals approximately 10.32 Therms;

"**Townsend Facility**" means the 198 Mmcf/d Townsend shallow-cut processing facility in northeast British Columbia owned by AltaGas Northwest Processing Limited Partnership;

"**Townsend Phase 2**" means the initial expansion of the Townsend Facility in two gas processing trains, the first train being a 99 Mmcf/d shallow-cut gas processing train to be located on the existing Townsend Facility site, adjacent to the currently operating Townsend Facility;

"**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;

"**Volcano Creek**" means the 16 MW run-of-river hydroelectric facility, one of the three run-of-river hydroelectric facilities in northwest British Columbia that forms part of the Northwest Hydro Facilities;

"**Washington Gas**" means Washington Gas Light Company, a subsidiary of WGL that sells and delivers natural gas primarily to retail customers in the District of Columbia, Maryland and Virginia in accordance with tariffs approved by the Public Service Commission of the District of Columbia, The Maryland Public Service Commission and The Commonwealth of Virginia State Corporation Commission;

"**Washington Gas Resources**" means Washington Gas Resources Corporation, a subsidiary of WGL that owns the majority of the non-utility subsidiaries;

"**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;

"**WGL**" means WGL Holdings, Inc.;

"**WGL Acquisition**" means the acquisition by AltaGas, indirectly through Merger Sub, of WGL through a merger of Merger Sub with and into WGL pursuant to the Merger Agreement;

"**WGL Energy Services**" means WGL Energy Services, Inc. (formerly Washington Gas Energy Services, Inc.), a subsidiary of Washington Gas Resources that sells natural gas and electricity to retail customers on an unregulated basis;

"**WGL Energy Systems**" means WGL Energy Systems, Inc. (formerly Washington Gas Energy Systems, Inc.), a subsidiary of Washington Gas Resources which provides commercial energy efficient and sustainable solutions to government and commercial clients;

"**WGL Midstream**" means WGL Midstream, Inc., a subsidiary of Washington Gas Resources that engages in acquiring and optimizing natural gas storage and transportation assets;

"**WGL Shares**" means the shares of common stock of WGL;

"**WGL Shareholder Approval**" means the affirmative vote (in person or by proxy) of the holders of more than two-thirds of the outstanding WGL Shares entitled to vote at a meeting of shareholders of WGL to consider the approval of the Merger Agreement, including any postponement, adjournment or recess thereof;

"**WGSW**" means WGSW, Inc., a subsidiary of Washington Gas Resources that was formed to invest in certain renewable energy projects; and

"**Younger**" 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	6.29
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

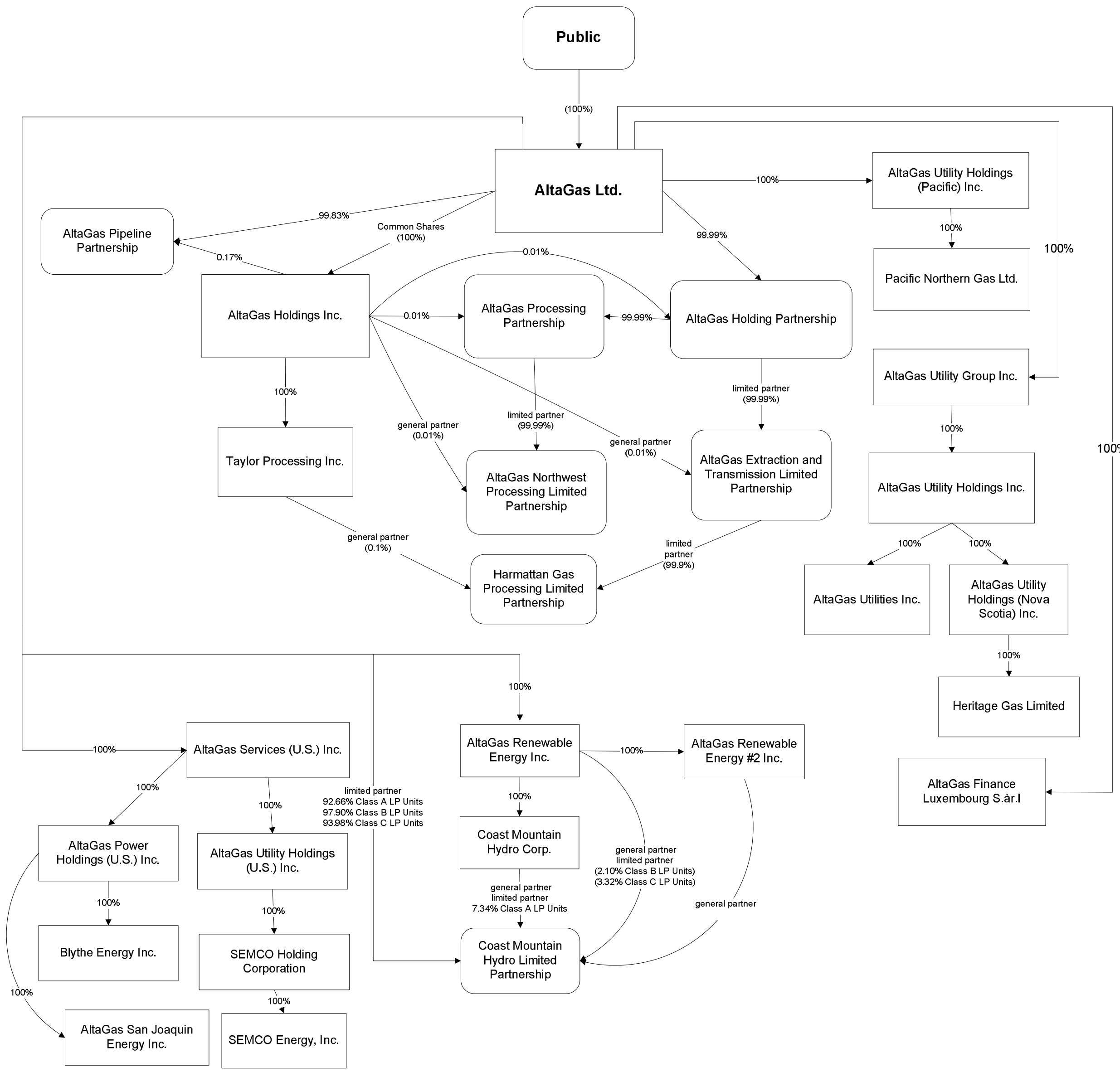
AltaGas Ltd. is a Canadian corporation amalgamated pursuant to the CBCA on July 1, 2010 and is the successor corporation resulting from the amalgamation of AltaGas Ltd., AltaGas Conversion Inc. and AltaGas Conversion #2 Inc. pursuant to the Corporate Arrangement. As a result of the Corporate Arrangement, AltaGas owns, directly or indirectly, all of the assets that the Trust owned, directly or indirectly, prior to the corporate conversion of the Trust**.** AltaGas Ltd. and/or its predecessors began operations in Calgary, Alberta on April 1, 1994 and AltaGas continues to maintain its head, principal and registered office in Calgary, Alberta currently located at 1700, 355 – 4th Avenue SW, Calgary, Alberta T2P 0J1. AltaGas is a public company trading on the TSX under the symbol "ALA".

AMENDED ARTICLES

On July 1, 2010 AltaGas filed articles of arrangement under the CBCA to effect the Corporate Arrangement and the amalgamation of AltaGas Ltd., AltaGas Conversion Inc. and AltaGas Conversion #2 Inc. to form AltaGas. Subsequent to the filing of the articles of arrangement, AltaGas has filed articles of amendment in connection with the creation of each series of Preferred Shares. Specifically, AltaGas filed articles of amendment on: (i) August 13, 2010 to create the first series of Preferred Shares, Series A Shares and second series of Preferred Shares, Series B Shares; (ii) June 1, 2012 to create the third series of Preferred Shares, Series C Shares and fourth series of Preferred Shares, Series D Shares; (iii) December 9, 2013 to create the fifth series of Preferred Shares, Series E Shares and the sixth series of Preferred Shares, Series F Shares; (iv) June 27, 2014 to create the seventh series of Preferred Shares, Series G Shares and the eighth series of Preferred Shares, Series H Shares; (v) November 17, 2015 to create the ninth series of Preferred Shares, Series I Shares and tenth series of Preferred Shares, Series J Shares; and (vi) February 15, 2017 to create the eleventh series of Preferred Shares, Series K Shares and the twelfth series of Preferred Shares, Series L Shares.

INTERCORPORATE RELATIONSHIPS

The following organization diagram presents the name and the jurisdiction of incorporation of certain of AltaGas' subsidiaries as at December 31, 2016. The diagram does not include all of the subsidiaries of AltaGas. The assets and revenues of those subsidiaries omitted from the diagram 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, 2016.



Note:

(1) Each of AltaGas Ltd., AltaGas Holdings Inc., AltaGas Utility Holdings (Pacific) Inc., AltaGas Utility Group Inc., AltaGas Utility Holdings Inc., AltaGas Utilities Inc. and Heritage Gas Limited is a corporation incorporated or formed by amalgamation or continuance under the CBCA. Each of AltaGas Utility Holdings (Nova Scotia) Inc., Taylor Processing Inc., AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership, AltaGas Pipeline Partnership, AltaGas Extraction and Transmission Limited Partnership and Harmattan Gas Processing Limited Partnership is a corporation, partnership or limited partnership (as applicable) incorporated, formed or established under the laws of Alberta. Each of AltaGas Renewable Energy Inc., AltaGas Renewable Energy #2 Inc., Coast Mountain Hydro Corp., Pacific Northern Gas Ltd. and Coast Mountain Hydro Limited Partnership is a corporation or limited partnership (as applicable) incorporated, formed or established under the laws of British Columbia. Each of AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., SEMCO Holding Corporation, AltaGas Power Holdings (U.S.) Inc., Blythe Energy Inc. and AltaGas San Joaquin Energy Inc. is a corporation formed under the laws of Delaware. AltaGas Holding Partnership is a partnership formed or established under the laws of Ontario, AltaGas Finance Luxembourg S.à r.l. is a private limited liability company formed under the laws of the Grand Duchy of Luxembourg and SEMCO Energy, Inc. is a corporation formed under the laws of Michigan.

OVERVIEW OF THE BUSINESS

AltaGas, a Canadian corporation, is a North American diversified energy infrastructure business with a focus on owning and operating assets to provide clean and affordable energy to its customers. AltaGas' business strategy is underpinned by strong growth in natural gas supply and the growing demand for clean energy. AltaGas has three business segments:

- Gas, which transacts more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, NGL extraction and separation, transmission, storage, and natural gas and NGL marketing, as well as the Corporation's indirectly held one-third interest in Petrogas through which its interest in the Ferndale Terminal is held;

- Power, which includes generation assets located across North America with 1,688 MW of gross capacity, all from natural gas and renewable sources, and 20 MW of energy storage; and

- Utilities, serving over 570,000 customers through ownership of regulated natural gas distribution utilities across North America and a regulated natural gas storage utility in the United States, delivering clean and affordable natural gas to homes and businesses.

As at December 31, 2016, AltaGas’ enterprise value exceeded $10 billion. With the physical and economic links along the energy value chain, together with its experienced and talented workforce of more than 1,600 people 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.

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, customer, 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 of its business segments. Superior service, safety, and reliability are also integral to AltaGas’ customer value proposition.

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 to provide a fully-integrated midstream service offering to its customers across the energy value chain. As part of this strategy, the Corporation builds and acquires gas gathering and processing infrastructure on behalf of, or from, producers wishing to redeploy capital to exploration and production activities, rather than to non-core activities such as midstream services. AltaGas seeks to move natural gas and NGL to key markets, including Asia. AltaGas is uniquely positioned to deliver higher netbacks to producers for NGL by establishing a western energy hub in northeast British Columbia, through the Ridley Island Propane Export Terminal currently under construction, and through its ownership interest in Petrogas and the Ferndale Terminal. AltaGas is focused on developing and operating larger gas infrastructure projects at lower cost. On January 25, 2017, the Corporation announced the WGL Acquisition. WGL has a growing midstream business with investments in gas gathering infrastructure and regulated gas pipelines in the Marcellus/Utica gas formation located in the northeast United States with capabilities for connections to marine-based energy export opportunities via the North American Atlantic coast through the proposed Cove Point LNG export facility in Maryland being developed by a third party, currently expected to be operational in late 2017. The combined enterprise will be uniquely positioned with key gas midstream assets in both the Marcellus/Utica and Montney gas formations, which are two of North America's most prolific gas basins. Further information on WGL's business can be found in the "Recent Developments" section of this AIF.

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, household, and C&I uses has increased substantially, providing significant opportunities across AltaGas' Gas, Power and Utilities segments to invest in and optimize assets.

Canada produces a surplus of gas, NGL and crude oil. The U.S. has traditionally been the sole export market for this surplus, but with the U.S. now having a surplus of these products, its demand for import of these products has decreased. As a result, netbacks have been less attractive for Canadian producers. AltaGas believes that energy market diversification is critical for the Canadian energy sector. Investing in infrastructure for export outside of North America provides an opportunity for Canadian producers to align the vast supply of NGL and natural gas reserves with the growing demand from Asia. AltaGas is uniquely positioned to provide producers with a competitive service offering across the integrated value chain, from wellhead to end markets by way of export terminals. Access to Asian markets provides market diversity to producers, especially those in the vast Montney and Duvernay basins under development in northeastern British Columbia and western Alberta. With the construction of the Ridley Island Propane Export Terminal, AltaGas will be in a position to provide multiple outlets for producers to deliver their products to the highest value markets. AltaGas is an experienced operator of LPG export terminals and operates the Ferndale Terminal. AltaGas has access to Asian markets through its relationship with Idemitsu who owns 51 percent of Astomos, the largest LPG importer in Japan (Mitsubishi Corporation owns the remaining 49 percent of Astomos).

The Power segment is focused on building, owning, and operating a diversified portfolio of clean energy assets that reduce the Corporation's carbon footprint and on meeting North America's demand for clean energy. There is a particular focus on increasingly cost competitive renewables and complimentary critical load balancing infrastructure across North America, as significant base load nuclear and coal-fired power generation is expected to be decommissioned over the next decade. AltaGas is well positioned to take advantage of this opportunity. The Corporation's pending acquisition of WGL fits synergistically with this strategy. WGL owns a growing non-regulated contracted power marketing business, with a focus on distributed generation and energy efficiency assets throughout the United States. WGL also owns a retail gas and power business serving approximately 260,000 customers across five states in the U.S. Further information on WGL's business can be found in the "Recent Developments" section of this AIF.

There has been an increase in the demand in North America for clean sources of highly flexible power to complement the significant growth in renewable power, while also helping to fill the void as coal and nuclear power declines. AltaGas is positioned to take advantage of this opportunity. In California, the CAISO has stated that up to 15,000 MW of fast ramping flexible capacity is required to meet the needs of the current 50 percent Renewable Portfolio Standard (RPS) of California by 2030 given planned retirements of once-through cooling gas facilities, as well as the planned retirements of the Diablo Canyon and San Onofre nuclear plants. With the retirements of traditional generating assets and the increased variability of a growing renewable asset base, the demand for highly-responsive generation and energy storage assets is increasing. In northern California, the Corporation is focused on owning generation assets in locally constrained areas near load pockets as local resource adequacy needs result in more opportunities for expansion, re-contracting and energy storage. AltaGas is well positioned in northern California with the acquisition of the San Joaquin Facilities and Ripon in 2015. In southern California, there has been an increasing demand for non-gas resource adequacy as evidenced by the Aliso Canyon storage request for proposals (RFPs), which has resulted in the successful bidding, construction and operation of the Pomona Energy Storage Facility, located in the East Los Angeles load pocket. This site is also well suited for future development of either additional battery storage or a repowering using a more flexible and efficient gas turbine. To the east of Pomona, near the border between southern California and Arizona, AltaGas is positioned at the convergence of transmission lines with multiple options available for contractual counterparties. The Blythe Energy Center along with potential expansion phases are in a position where generation can be delivered to customers in the CAISO, and other neighboring states such as Arizona in the Western Area Power Administration (WAPA). The Corporation expects further development and expansion opportunities to arise for brownfield sites similar to the recently completed Pomona Energy Storage Facility.

In the Utilities segment, the Corporation is focused on finding innovative ways to continue to safely and reliably deliver clean and affordable natural gas to more customers. AltaGas focuses on growing rate base through adding customers, including serving power plants within service jurisdictions, and improving and upgrading existing infrastructure to meet increased residential and commercial demand. The Corporation also seeks to execute strategic utility acquisitions and dispositions when opportunities arise. Further information on the WGL Acquisition and on Washington Gas can be found in the "Recent Developments" section of this AIF.

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, and fuel switching as abundant natural gas provides a clean low cost energy alternative. In addition, the Utilities continue to invest in existing distribution systems through pipeline replacement and system betterment programs to ensure safe, reliable service for AltaGas' customers. The Alton Natural Gas Storage Project currently under construction in Nova Scotia will help increase reliability of supply to AltaGas' natural gas distribution customers in that area.

Integral to AltaGas' strategy is maintaining financial strength and flexibility, an investment grade credit rating, and ready access to capital markets.

Financial discipline and effective risk management are fundamental cornerstones of the Corporation's strategy. AltaGas seeks to optimize risk and reward, ensuring that returns are commensurate with the level of risk assumed. 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 ensure investment grade credit ratings, diversity in its funding sources, and ready access to capital markets.

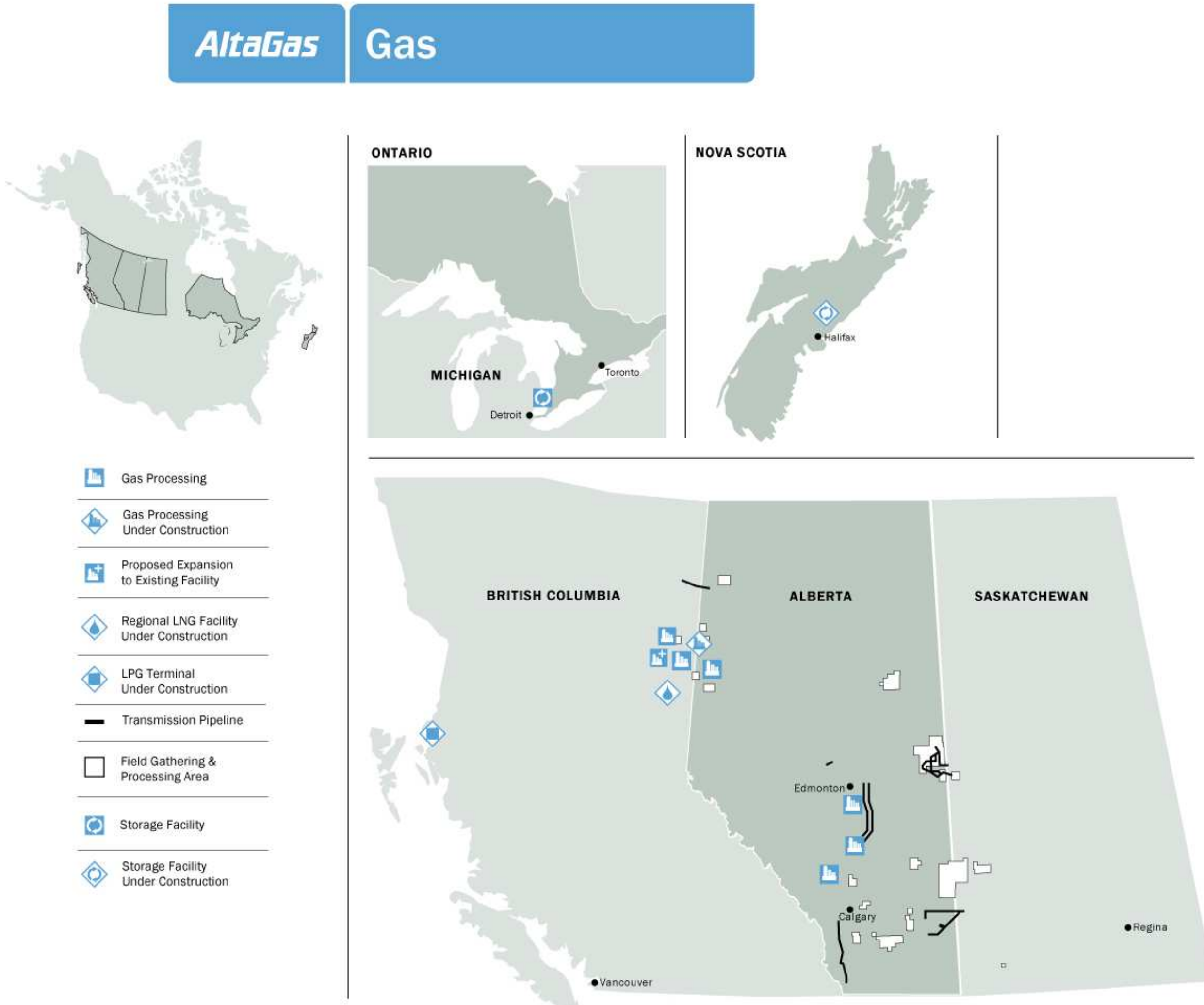
A key element of the Corporation's stable business model is mitigating its exposure to certain market price risks as well as volume risk. In addition to its diversification strategy, the Corporation has developed risk management processes that mitigate earnings volatility from commodity price risk and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

AltaGas strives to employ the best available practices and technologies for integrity management systems, and maintenance and operations in order to mitigate risks to customers, the public, employees and the environment. AltaGas' number one core value is to operate in a safe and reliable manner. AltaGas has the internal capabilities and resources to safely deliver capital projects on time and on budget, in close partnership with First Nations and community stakeholders. AltaGas has significant in-house construction expertise, demonstrated by the successful completion of more than $2.0 billion in projects over the last few years, which provides a significant competitive advantage. Cost efficiency and strong 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.

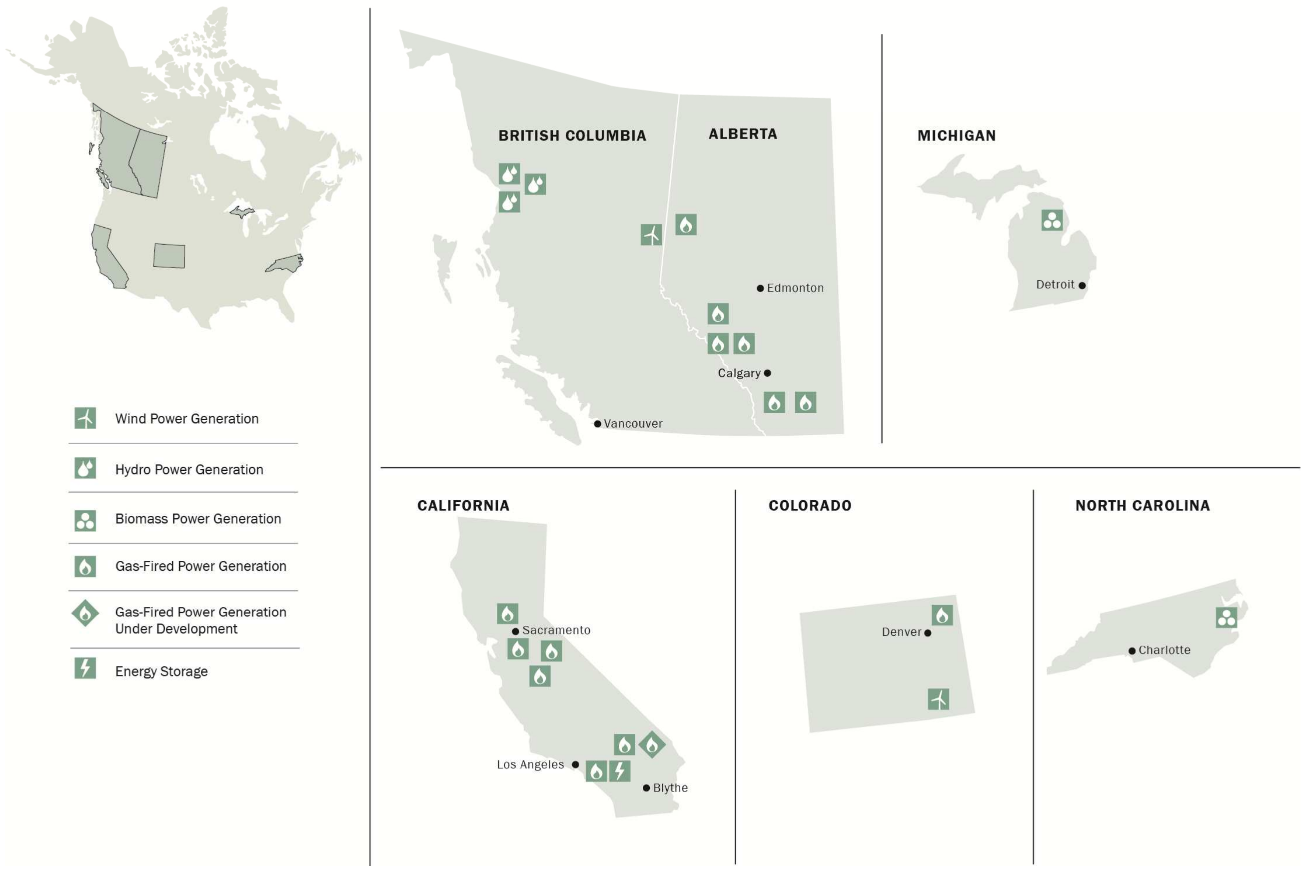
Consistent with its mandate of overseeing and directing the Corporation's strategic direction, AltaGas' Board of Directors reviews the Corporation's strategy on an annual basis. The Corporation continually assesses the macro- and micro-economic trends impacting its business and seeks opportunities to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

For more details on AltaGas' strategy and strategy execution please refer to the Annual MD&A.

ALTAGAS' GEOGRAPHIC FOOTPRINT



Power



Wind Power Generation
Hydro Power Generation
Biomass Power Generation
Gas-Fired Power Generation
Gas-Fired Power Generation Under Development
Energy Storage
BRITISH COLUMBIA
ALBERTA
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Calgary
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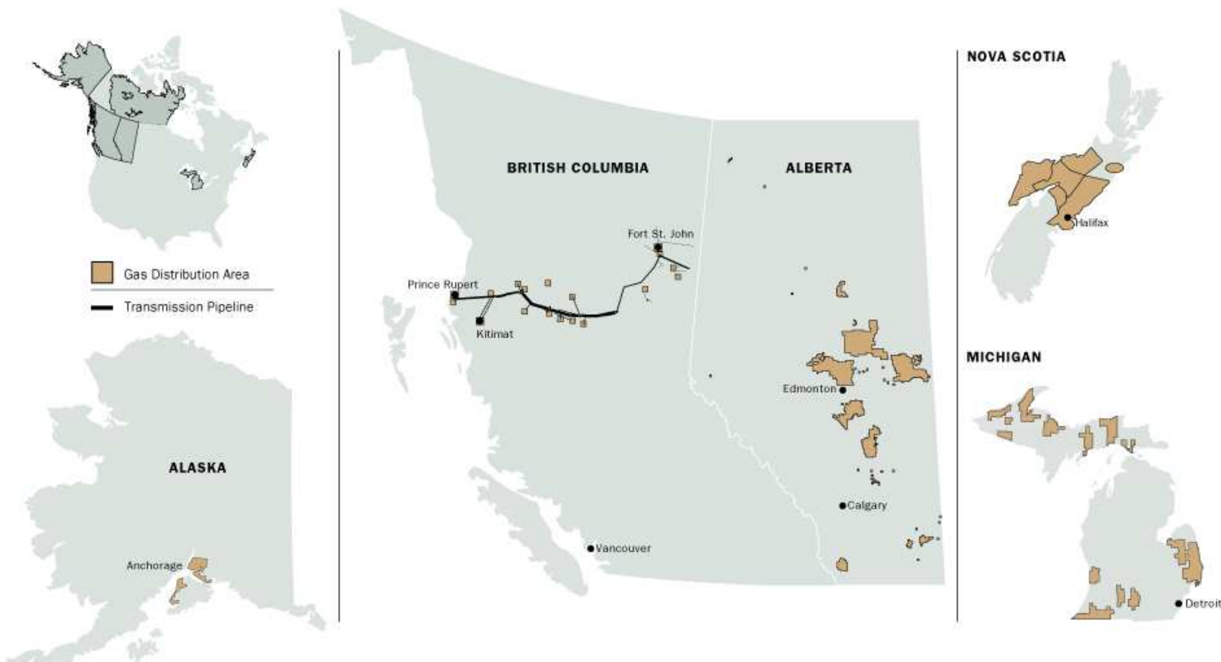
MICHIGAN
Detroit
CALIFORNIA
Sacramento
Los Angeles
Blythe
COLORADO
Denver
NORTH CAROLINA
Charlotte

AltaGas Utilities



GENERAL DEVELOPMENT OF ALTAGAS' BUSINESS

Below is a summary by business segment of certain acquisitions and dispositions, key development and construction projects and other commercial arrangements, which have influenced the general development of such business segment of the Corporation over the last three completed financial years as well as a summary of certain recent developments in 2017.

RECENT DEVELOPMENTS

WGL Acquisition

On January 25, 2017, AltaGas, Merger Sub and WGL entered into the Merger Agreement pursuant to which Merger Sub will be merged with and into WGL, with WGL continuing as the surviving corporation and as an indirect wholly-owned subsidiary of AltaGas, and the WGL Shares (other than any WGL Shares held immediately prior to the effective time by WGL or any of its subsidiaries or by AltaGas, Merger Sub or any of their respective subsidiaries) will be automatically converted into and represent only the right to receive US$88.25 in cash per WGL Share, without interest. The aggregate purchase price to be paid, including pursuant to any outstanding equity awards under WGL's benefit plans, is approximately $6.0 billion in cash and does not include the outstanding debt of WGL and its subsidiaries and the preferred shares of Washington Gas totaling approximately $2.4 billion at September 30, 2016, which AltaGas expects will remain outstanding.

The WGL Acquisition is expected to close shortly after the later of: (a) the expiration or termination of the applicable waiting period (and any extensions thereof) in connection with the WGL Acquisition under the HSR Act; (b) receipt of WGL Shareholder Approval; and (c) receipt of the Regulatory Approvals, provided that all such conditions and certain other customary closing conditions are satisfied or waived on or prior to 5:00 p.m., Washington D.C. time on January 25, 2018, subject to extension in certain circumstances to a date that is not later than 180 days thereafter. For further details on the Merger Agreement please see a copy of the Merger Agreement filed with Canadian securities regulatory authorities on SEDAR at www.sedar.com.

The closing of the WGL Acquisition is expected to occur by the end of the second quarter of AltaGas' fiscal year 2018 and following the closing of the WGL Acquisition AltaGas is expected to have approximately $22 billion of assets and over 1.7 million utility segment customers.

AltaGas expects that cash to close the WGL Acquisition of approximately $6.0 billion will be provided from a combination of: (a) the net proceeds from the Offering and the Concurrent Private Placement; (b) the Bridge Facility; (c) the net proceeds from certain planned divestitures of assets of AltaGas; and (d) future senior debt, hybrid security, equity or equity-linked security (including any Preferred Shares or convertible debentures) financings. AltaGas currently expects to fund approximately $0.8 billion through hybrid security or Preferred Share issuances and a further approximately $2.7 billion through asset divestitures and, if required, the Bridge Facility.

Business of WGL

Headquartered in Washington D.C., WGL is a New York Stock Exchange listed, diversified utility holding company with four reportable operating segments: regulated utility, retail energy marketing, commercial energy systems and midstream energy services. The regulated utility segment is WGL's core business and consists of WGL's principal subsidiary, Washington Gas, a regulated natural gas LDC serving customers in the District of Columbia, Maryland and Virginia and its subsidiary, Hampshire, which provides regulated interstate natural gas storage services to Washington Gas under a FERC approved interstate storage service tariff. WGL owns all of the shares of common stock of Washington Gas, Washington Gas Resources and Hampshire. Washington Gas Resources owns four unregulated subsidiaries that include WGL Energy Services, WGL Energy Systems, WGL Midstream and WGSW. Additionally, several subsidiaries of WGL own interests in other entities. Each of WGL's operating segments is more particularly described below.

Washington Gas Light Company (Washington Gas)

Washington Gas has been engaged in the natural gas distribution business since 1848, and provides regulated gas distribution services to end users in District of Columbia, Virginia, and Maryland. Washington Gas is a respected utility with constructive relationships with all three of its regulators. The utility has approximately 1.1 million customers across these three jurisdictions: District of Columbia (~158,000; 14 percent), Maryland (~469,000; 41 percent), and Virginia (~517,000; 45 percent). Washington Gas operations are such that the loss of any one customer or group of customers would not have a significant adverse effect on its business.

Washington Gas' customers are eligible to purchase their natural gas from unregulated third-party marketers through natural gas unbundling; approximately 180,000 or approximately 16 percent of its customers have chosen to do so as at Washington Gas' fiscal year-end 2016. This does not negatively impact Washington Gas' net income as the company does not earn a margin on the sale of natural gas, but only from the delivery and distribution of the gas.

Washington Gas obtains natural gas supplies that originate from multiple regions throughout the U.S. As at its 2016 fiscal year-end, it had service agreements with four pipeline companies that provided firm transportation and storage services, with contract expiration dates ranging from 2017 to 2034. Washington Gas has also contracted with various interstate pipeline and storage companies to add to its storage and transportation capacity for 2016-2019.

Hampshire Gas Company (Hampshire)

Hampshire owns full and partial interests in 30 Bcf of underground natural gas storage facilities, including pipeline delivery facilities located in and around Hampshire County, West Virginia, and operates these facilities to serve Washington Gas. Washington Gas purchases all of the storage services of Hampshire, and includes the cost of the services in its regulated energy bills to customers. Hampshire operates under a "pass-through" cost of service based tariff approved by FERC.

Regulatory Environment

Washington Gas is regulated by the Public Service Commission of the District of Columbia, The Maryland Public Service Commission and The Commonwealth of Virginia State Corporation Commission, which approve its terms of service and the billing rates that it charges to its customers. Hampshire is regulated by FERC.

The rates charged to utility customers are designed to recover Washington Gas' operating expenses and natural gas commodity costs and to provide a return on its investment in the net assets used in its firm gas sales and delivery service.

WGL Midstream

WGL Midstream specializes in the investment, management, development and optimization of natural gas storage and transportation midstream infrastructure projects. WGL Midstream provides natural gas related solutions to its customers and counterparties including producers, utilities, local distribution companies, power generators, wholesale energy suppliers, LNG exporters, pipelines and storage facilities. Moreover, WGL Midstream contracts for storage and pipeline capacity in its trading activities through both long term contracts and short term transportation releases. WGL Midstream also contracts for physical natural gas sales and purchases on both a long term and short term basis.

As at WGL's fiscal year end of September 30, 2016, WGL Midstream had pipeline investments totalling US$237.3 million. Midstream investments have typically been in regulated gas pipelines that are expected to have a majority of the capacity covered under long-term contracts. In the fiscal year ended September 30, 2016, WGL Midstream invested US$158.1 million in pipelines.

Stonewall Gas Gathering System (30 percent net interest)

As at September 30, 2016, WGL Midstream held a 30 percent equity interest in an entity that owns and operates certain assets known as the Stonewall System for an equity method investment of US$95.5 million. The Stonewall System has the capacity to gather up to 1.4 Bcf/d of natural gas from the Marcellus production region in West Virginia, and connects with an interstate pipeline system that serves markets in the mid-Atlantic region. As at June 30, 2016, other owners in the pipeline included DTE Energy Company and Antero Midstream Partners LP.

Central Penn (21 percent net interest)

In February 2014, WGL Midstream and certain partners formed, and WGL Midstream acquired, a 55 percent interest in Meade Pipeline Co LLC (Meade). Meade was formed to develop and own, jointly with Transcontinental Gas Pipeline Company, LLC (Transco), an approximately 185-mile regulated pipeline originating in Susquehanna County, Pennsylvania and extending to Lancaster County, Pennsylvania that will have the capacity to transport and deliver up to approximately 1.7 million dekatherms per day of natural gas. Central Penn currently has a projected in-service date of mid-2018.

Central Penn is anticipated to be an integral part of Transco's "Atlantic Sunrise" project and will be fully integrated into Transco's system. WGL Midstream is anticipated to invest an estimated US$410.0 million for its interest in Meade, and Meade is anticipated to invest an estimated US$746 million in Central Penn for an approximate 39 percent interest in Central Penn. As at September 30, 2016, WGL Midstream had invested US$80.1 million in Central Penn.

Additionally, in February 2014, WGL Midstream entered into an agreement with Cabot Oil & Gas Corporation whereby WGL Midstream will purchase 500,000 dekatherms per day of natural gas from Cabot over a 15 year term. As part of this agreement, Cabot Oil & Gas Corporation has acquired 500,000 dekatherms per day of firm gas transportation capacity on Transco's Atlantic Sunrise project of which Central Penn is a part.

Mountain Valley (10 percent net interest)

WGL Midstream owns a 10 percent interest in Mountain Valley Pipeline, LLC. The proposed pipeline to be developed, constructed, owned and operated by Mountain Valley Pipeline, LLC will transport approximately 2.0 million dekatherms of natural gas per day from two interconnects with EQT Corporation's Equitrans system in West Virginia to Transco's Station 165 in Pittsylvania County, Virginia. The pipeline is scheduled to be in service by December 2018. The total project investment is anticipated to be approximately US$3.3 billion. WGL Midstream will invest, in scheduled capital contributions through the in-service date of the pipeline, its pro rata share (based on its 10 percent equity interest) of project costs, for an estimated aggregate amount of approximately US$326.4 million. In addition, WGL Midstream entered into a gas purchase commitment to buy 500,000 dekatherms of natural gas per day, at index-based prices, for a 20 year term, and will also be a shipper on the proposed pipeline. As at September 30, 2016, WGL Midstream had an equity method of investment of US$22.5 million in Mountain Valley. As at January 22, 2016, other owners in the pipeline included EQT Midstream Partners, LP, NextEra US Gas Assets, LLC, Con Edison Gas Midstream, LLC and RGC Midstream, LLC.

Constitution (10 percent net interest)

In 2013, WGL Midstream invested in Constitution Pipeline Company, LLC (Constitution). The pipeline project is designed to transport at least 650,000 dekatherms of natural gas per day from the Marcellus production areas in Susquehanna County, Pennsylvania, and interconnect with the Iroquois Gas Transmission and Tennessee Gas Pipeline systems in Schoharie County, New York to deliver gas to major Northeastern US markets. Constitution has a target in-service date in the second half of 2018. The project is currently fully contracted with long term commitments from established natural gas producers operating in Pennsylvania. As at September 30, 2016, WGL Midstream had invested US$38.6 million in Constitution. As at September 30, 2016, other owners in the pipeline included Williams Partners Operatings, LLC, Cabot Oil & Gas Corporation and an affiliate of Piedmont Natural Gas Company.

At September 30, 2016, WGL Midstream's total share of the cost of Constitution is estimated to be US$95.5 million over the term of the agreement, reflecting a 10 percent share in the pipeline venture. On December 2, 2014, FERC issued an order granting a certificate of public convenience and necessity. On April 22, 2016, the NYSDEC denied Constitution's application for a Section 401 Certification for the pipeline, which is necessary for the construction and operation of the pipeline. Constitution has stated that it remains committed to pursuing the project and that it intends to pursue all available options to challenge the legality and appropriateness of NYSDEC's decision. In May 2016, Constitution filed actions in both the U.S. Circuit Court of Appeals for the Second Circuit and the U.S. District Court for the Northern District of New York, appealing the decision and seeking declaratory judgment that the State of New York's permitting authority is pre-empted by federal law. The courts have granted Constitution's motions to expedite the schedules for these legal actions.

Cove Point LNG Export Facility

On December 4, 2014, WGL Midstream entered into a gas sale and purchase, and capacity agreement with GAIL Global (USA) LNG LLC, a subsidiary of GAIL (India) Limited, under which WGL Midstream has agreed to sell a minimum of 340,000 Dekatherms/day and up to 430,000 Dekatherms/day of natural gas, for a term of approximately 20 years commencing on the in-service date of the proposed Cove Point LNG export facility being developed by a third party and expected to be operational in late 2017. The natural gas is intended to be liquefied at this proposed export facility.

Commercial Energy Systems (CES)

WGL Energy Systems and WGSW

The commercial energy systems segment consists of the operations of WGL Energy Systems, WGSW and the results of operations of affiliate owned commercial distributed energy projects.

CES focuses on clean and energy efficient solutions for its customers, driving earnings through (i) owning and operating distributed generation assets; primarily solar photovoltaic systems, but also natural gas fuel cells and other storage technologies which provide energy to customers, and (ii) operating as a general contractor to upgrade the mechanical, electrical, water and energy-related infrastructure of large governmental and commercial facilities by implementing both traditional and alternative energy technologies. This business segment has assets and activities across the United States.

As of WGL's fiscal year end of September 30, 2016, this segment owned US$547.2 million of operating distributed generation assets, having invested US$163.8 million during the 2016 fiscal year, generating a total of 211,495 MWh in fiscal year 2016. Additionally, as of September 30, 2016, there was US$157.3 million of signed projects under construction. These distributed generation assets drive revenue through the sale of renewable power generation under long-term power purchase agreements and the sale of renewable energy credits.

Retail Energy Marketing

WGL Energy Services

WGL's unregulated activities include WGL Energy Services, a retail energy marketing segment, which sells natural gas, electricity, wind/renewable energy credits and carbon offsets directly to residential, commercial and industrial customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. As at September 30, 2016, WGL Energy Services served approximately 133,000 residential, commercial and industrial natural gas customer accounts and approximately 127,400 residential, commercial and industrial electricity customer accounts located in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. WGL Energy Services is subject to regulation by the public service regulatory commission of the states in which the company is authorized as a competitive service provider. On February

20, 2013, WGL Energy Services entered into a five-year secured supply arrangement with Shell Energy North America (US), LP (Shell Energy). Under this arrangement, WGL Energy Services has the ability to purchase the majority of its power, natural gas and related products from Shell Energy in a structure that reduces WGL Energy Services' cash flow risk from collateral posting requirements. While Shell Energy is intended to be the majority provider of natural gas and electricity, WGL Energy Services retains the right to purchase supply from other providers. On November 7, 2016, the supply arrangement was extended for two years, expiring in 2020. WGL Energy Services owns solar generating assets which are dedicated to five specific customers. The results of operations for these assets are reported within the Commercial Energy Systems segment. WGL Energy Services does not own or operate any other electric generation, transmission or distribution assets.

Development of the Gas Business of AltaGas

In February 2014, AltaGas acquired the remaining 50 percent ownership interest in Alton Natural Gas Storage L.P., which owns the Alton Natural Gas Storage Facility. AltaGas acquired its initial 50 percent interest in Alton Natural Gas Storage L.P. pursuant to the acquisition of Landis Energy Corporation in 2010. The Alton Natural Gas Storage Facility is expected to provide up to 10 Bcf of natural gas storage capacity, construction is underway and AltaGas currently expects this facility to be in service in 2020.

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 owned one-third by each of AltaGas, Idemitsu and its original shareholder. Petrogas' extensive logistics network consists of over 1,800 rail cars and 24 rail and truck terminals in Canada and the U.S. In May 2014, AltaGas signed an agreement with Petrogas for AltaGas to operate the Ferndale Terminal.

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 LNG facilities throughout northern British Columbia. An initial pilot facility has been constructed in Dawson Creek, with commercial operation beginning in early 2017. The facility has capacity of approximately 30,000 gallons per day and includes a liquefaction plant, storage and distribution equipment.

In August 2014, AltaGas signed agreements to enter into a 15-year strategic alliance with Painted Pony for the development of processing infrastructure and marketing services for natural gas and NGLs. In the first phase of the strategic alliance, AltaGas constructed the Townsend Facility, together with a 25 km gas gathering pipeline, two liquids egress pipelines totaling 30 km and a truck terminal. The Townsend Facility commenced commercial operations in July of 2016.

Effective January 1, 2016, AltaGas acquired the remaining 51 percent interest in EEEP.

On February 29, 2016, as part of AltaGas' strategy to focus on larger scale opportunities in the Gas segment that support AltaGas' northeast British Columbia strategy, AltaGas completed the sale of certain non-core natural gas gathering and processing assets located primarily in central and north central Alberta, totaling approximately 490 Mmcf/d of gross licensed natural gas processing capacity for total consideration of $30 million of cash and approximately 43.7 million of common shares of Tidewater Midstream and Infrastructure Ltd., representing approximately 15 percent of common shares as at December 31, 2016.

In October 2016, AltaGas reached a positive final investment decision for the construction, ownership and operation of the North Pine Facility and the North Pine Pipelines. In conjunction with the North Pine Facility, AltaGas submitted an application to the BCOGC for the North Pine Pipelines, which will run from AltaGas' existing Alaska highway truck terminal to the North Pine Facility. The North Pine Facility will be connected to existing AltaGas infrastructure in the region and will have access to the CN rail network, allowing for the transportation of specification product from the North Pine Facility, including transportation of propane, to AltaGas' Ridley Island Propane Export Terminal. On December 16, 2016, AltaGas received its permits for the construction of the North Pine Pipelines. Site preparation for the North Pine Facility and the North Pine Pipelines is underway with a target commercial on-stream date in the second quarter of 2018. AltaGas expects to construct a second 10,000 Bbls/d NGL separation train following completion of the first train and provided that there is sufficient support from area producers.

On December 19, 2016, AltaGas received approval from the BCOGC for Townsend Phase 2 and to retrofit the existing shallow-cut Townsend Facility to a deep-cut facility at a future date if AltaGas elects to do so. AltaGas will be constructing Townsend Phase 2 in two separate gas processing trains. The first train will be a 99 Mmcf/d shallow-cut gas processing facility to be located on the existing Townsend site, adjacent to the currently operating Townsend Facility. NGL produced from Townsend Phase 2 is expected to be transported approximately 70 km to AltaGas' North Pine Facility via existing and planned NGL pipelines owned by AltaGas. On February 22, 2017, the Board of Directors approved a positive FID for the first train of Townsend Phase 2. Long-lead major equipment has been ordered and the first train of Townsend Phase 2 is expected to begin commercial operation in October 2017. The first train of Townsend Phase 2 and the field compression equipment are expected to be fully contracted with Painted Pony under a 20-year take-or-pay agreement.

In January 2017, AltaGas reached a positive final investment decision on the Ridley Island Propane Export Terminal. The Ridley Island Propane Export Terminal is expected to be the first propane export facility off the west coast of Canada. The site is near Prince Rupert, British Columbia, on a section of land leased by Ridley Terminals Inc. from the Prince Rupert Port Authority. The locational advantage of the site is very short shipping distances to markets in Asia, notably a 10-day shipping time compared to 25-days from the U.S. Gulf Coast. The brownfield site also benefits from excellent railway access and a world class marine jetty with deep water access to the Pacific Ocean. Construction is expected to begin in the first quarter of 2017. The Ridley Island Propane Export Terminal is expected to be in service by the first quarter of 2019. For further details on this project see sub-heading "Gas Business – Energy Export".

Development of the Power Business of AltaGas

In 2014, AltaGas commissioned the 195 MW Forrest Kerr and 16 MW Volcano Creek facilities in British Columbia. In 2015, the 66 MW McLymont Creek facility, the third and final of the Northwest Hydro Facilities to come online, was commissioned. The Northwest Hydro Facilities 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.

In 2014, AltaGas acquired Blythe II and Blythe III for possible expansion opportunities of generation capacity in California. These sites offer potential contracting opportunities for future projects with multiple creditworthy utilities and regional municipalities in California and adjacent states, as well as corporations. Development activities are underway for these sites and could potentially result in tripling the existing generation capacity in the vicinity of the Blythe Energy Center.

Effective January 8, 2015, AltaGas acquired three U.S. gas-fired power assets (Ripon, Pomona, and Brush II) with a total generation capacity of 164 MW for approximately US$28 million. Ripon is located in northern California, Pomona is located is southern California, and Brush II is located in Colorado. Ripon and Brush II are currently contracted under PPAs with local creditworthy utilities, and generate stable cash flows. The Pomona Facility has now fully transitioned to operate on a merchant market basis.

In 2015, AltaGas completed Cogeneration III. The 15 MW cogeneration facility provides steam for gas processing while providing clean base-load power to the Alberta power market.

Effective November 30, 2015, AltaGas acquired the San Joaquin Facilities in Northern California with a total generating capacity of 523 MW, for approximately US$642 million, before working capital adjustments. All three facilities (Tracy, Hanford and Henrietta) are currently contracted under long-term PPAs with a creditworthy utility through 2022, providing low-risk and fully contracted cash flows.

Pursuant to the change in law provision of the Sundance B PPAs, ASTC Power Partnership, a joint venture partnership between TransCanada Energy Ltd. and AltaGas, exercised its right to terminate the Sundance B PPAs effective March 8, 2016. In December 2016, a definitive settlement agreement was reached with the Government of Alberta accepting termination of the Sundance B PPAs effective March 8, 2016. Under the settlement agreement, AltaGas agreed to contribute 391,879 self-generated carbon offsets and to make total cash payments in the aggregate amount of $6 million, payable in equal installments over three years starting in 2018 and the Government of Alberta granted AltaGas a full release from all obligations with respect to the Sundance B PPAs. Following the termination of the Sundance B PPAs, AltaGas has fully transitioned its power segment to be a 100 percent clean energy provider with approximately 74 percent and 26 percent of generation capacity from gas-fired and renewables sources, respectively.

On December 31, 2016 AltaGas successfully commissioned the Pomona Energy Storage Facility. For further details see sub-heading "Power Business".

Development of the Utilities Business of AltaGas

In January 2015, SEMCO Gas filed a MRP case requesting to continue the current MRP program for an additional five years and to increase its MRP surcharge. 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 million. In June 2015, the MPSC approved this filing and the new rates became effective immediately following the approval.

ENSTAR filed a base rate case with the RCA in September 2014, which included a request for an interim and refundable rate increase. In October 2014, the RCA approved ENSTAR’s request for an interim and refundable rate increase of approximately 1.0 percent that became effective November 1, 2014. In July 2015, the parties to ENSTAR’s rate case proceeding reached an agreement in principle to settle the case and a stipulation was filed and accepted by the RCA in September 2015. As part of the stipulation, ENSTAR agreed to a 2016 rate case to be filed by June 1, 2016, with a 2015 test year. In accepting the stipulation, the RCA also allowed a permanent rate increase effective October 1, 2015, of approximately 2.2 percent over the interim and refundable rates that went into effect on November 1, 2014, the parties agreed that there would not be any refunds of the interim and refundable rate increase that went into effect on November 1, 2014 and another interim and refundable rate increase of approximately 0.8 percent was granted to go into effect on January 1, 2016, pending resolution of the 2016 rate case. On June 1, 2016, ENSTAR filed the 2016 rate case requesting an overall annual base rate increase of approximately US$12 million, or 3.9 percent on total revenues and a decision is expected in third quarter of 2017. On July 18, 2016, the RCA approved ENSTAR’s request for an additional 1.6 percent interim and refundable rate increase on total revenues, effective August 1, 2016.

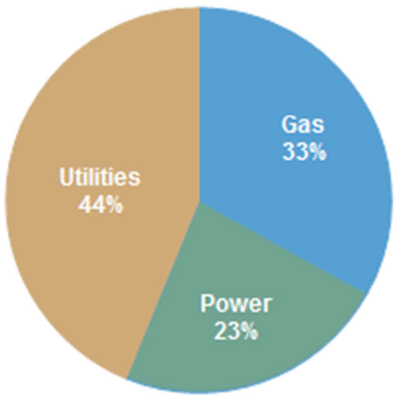
In September 2016, the NSUARB approved Heritage Gas’ Customer Retention Program application to decrease distribution rates for certain commercial and residential customers, suspend depreciation and to increase the capitalization rate for operating, maintenance and administrative expenses effective March 22, 2016. For further details please refer to "Business of the Corporation – Heritage Gas - Material Regulatory Developments and Applications".

On December 15, 2016, SEMCO Gas filed an application with the MPSC seeking approval to construct, own, and operate the MCP. The MCP is a proposed new pipeline that will connect the Great Lakes Gas Transmission pipeline to the Northern Natural Gas pipeline in Marquette, Michigan where it will provide system redundancy and increase deliverability, reliability and diversity of supply to SEMCO Gas’ approximately 35,000 customers in Michigan's Western Upper Peninsula. A MPSC decision is expected in the fourth quarter of 2017.

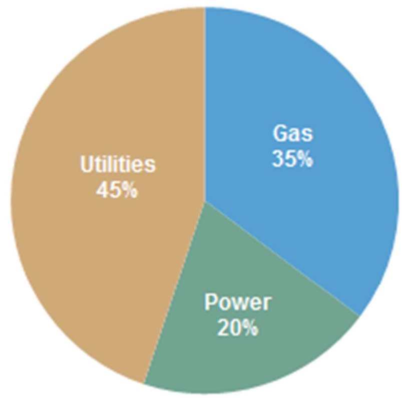
BUSINESS OF THE CORPORATION

AltaGas' revenue for the year-ended December 31, 2016 was $2.2 billion, consistent with the year-ended December 31, 2015.

Revenue by Business for 2016 (1)



Revenue by Business for 2015 (1)



Note:
(1) Excluding Corporate segment and intersegment eliminations

OPERATING BUSINESSES

AltaGas operates its business through three business segments: Gas, Power and Utilities, each of which is more particularly described in this section. AltaGas' business also includes the Corporate segment, which consists primarily of opportunistic investments, risk management contract results and revenues and expenses not directly identifiable with the operating businesses.

GAS BUSINESS

AltaGas' Gas business contributed revenue of $804 million for the year ended December 31, 2016 (2015 - $845 million), representing approximately 33 percent (2015 – 35 percent) of AltaGas' total revenue before Corporate segment and intersegment eliminations. The Gas business is primarily comprised of AltaGas' extraction and field gathering and processing business described below. AltaGas also owns certain non-material transmission assets and transmission pipelines. To support its gas business, AltaGas conducts an energy service business mainly focused on natural gas and NGL marketing initiatives. AltaGas is also pursuing energy export initiatives and constructing the Alton Natural Gas Storage Facility.

Gas Business - Extraction

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 as at December 31, 2016 of AltaGas' operatorship, capacity and total production associated with extraction and fractionation plants in which AltaGas holds an interest:

Extraction or Fractionation Plant	Location	Interest (%)	AltaGas' Inlet Processing Capacity (Mmcf/d)	Operated or Non-Operated
Harmattan	Central Alberta	100.00	490	Operated
Younger	Taylor, British Columbia	56.67	425	Operated
JEEP	Joffre, Alberta	100.00	250	Operated
EEEP	Edmonton, Alberta	100.00	390	Operated
Empress Pembina	Empress, Alberta	11.25	135	Non-Operated
Empress ATCO[1]	Empress, Alberta	7.17	0	Non-Operated
Total[2]			**1,690**	

Notes:
(1) The Empress ATCO extraction plant was shut-in April 2015 and there has been no production since that time; decommissioning of the facility began in late 2016 and is expected to be completed in 2017.
(2) Excludes Bantry fractionator products and field NGLs.

Total Liquids Production (Bbls/d)[1]

	2016	2015
NGLs [2]	**27,517**	24,236
Ethane	**32,233**	32,250

Notes:
(1) Average volumes for the fourth quarter.
(2) Excludes Bantry fractionator products and field NGLs.

Extraction - Plant Fee Structures

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 heating 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. 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' NGL production is sold under a variety of arrangements. At December 31, 2016, approximately 73 percent of AltaGas' NGL production was sold under long-term, fee-for-service contracts. Fee-for-service means that fees are charged to the customer for the service provided on a per unit volume basis. 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, 2016, approximately 27 percent of AltaGas' NGL production (12 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.

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 – 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, co-stream processing, 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 carbon dioxide (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.

Approximately 30 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 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 entered into a co-stream processing agreement with Nova Chemicals related to ethane and NGL extraction at Harmattan in 2012 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" in this AIF.

Extraction – Younger

AltaGas owns a 56.67 percent interest in Younger. The remaining interest is held by Pembina. Younger 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 which brings liquids-rich gas from the Montney area of British Columbia to Younger.

Younger has a licence capacity to process up to 750 Mmcf/d of natural gas and AltaGas' share of such capacity is 425 Mmcf/d. AltaGas owns 100 percent of the facilities related to fractionation, storage, loading, treating or terminalling of NGLs.

All of AltaGas' NGL production from Younger is marketed by 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 Younger as part of the NGL purchase agreement. The NGL purchase agreement expires in 2018 and Pembina has an option to prepay for an ownership change in 2017.

AltaGas' ethane production is sold to Dow Chemicals under a long-term fee-for-service contract.

Extraction - Joffre Ethane Extraction Plant

AltaGas owns 100 percent of JEEP which has processing capacity of 250 Mmcf/d of natural gas and is capable of producing up to 10,400 Bbls/d of ethane and NGLs.

The plant 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 owns 100 percent of EEEP. EEEP is directly connected to the Alberta Ethane Gathering System and to Plains Midstream Canada's Co-Ed NGL pipeline.

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 – North Pine Facility

AltaGas has reached a positive final investment decision for the construction, ownership and operation of the North Pine Facility and North Pine Pipelines. Site preparation for the construction of the North Pine Facility and the North Pine Pipelines is underway with a target commercial on-stream date in the second quarter of 2018. For further details on the North Pine Facility and North Pine Pipelines see "Development of the Gas Business of AltaGas" sub-heading under "General Development of AltaGas' Business".

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.

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.

Younger 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 Younger 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 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 30 gathering and processing facilities located in 12 operating areas in Western Canada and approximately 5,300 km of gathering and sales 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 approximately 1.1 Bcf/d, of which 26 percent was capable of processing sour gas. AltaGas operates all but two 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.

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.

NGLs generally have greater value if extracted in liquid form and additional NGL recovery beyond downstream pipeline specifications may be carried out in order to capture the value of the NGLs. This additional recovery process can be done at field gas plants or at large-scale extraction plants. See "Gas Business – Extraction". AltaGas has NGL extraction capability at 12 of its natural gas field processing facilities.

The main drivers of the field gathering and processing business 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 - Facilities

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.

Field Gathering and Processing Facility Capacity and Throughput

	2016	**2015**
Licensed capacity (gross Mmcf/d)(1)(2)	**1,101**	1,355
Throughput (gross fourth quarter Mmcf/d)(2)	**365**	389
Capacity utilization (%)	**33**	29

Notes:
(1) As at December 31, 2016 and 2015.
(2) Gross numbers are not adjusted to reflect AltaGas' working interest.

Average facility utilization increased to 33 percent in 2016 from 29 percent in 2015 due to volumes processed at the Townsend Facility.

Field Gathering and Processing - Significant Operating Areas and Customers

Approximately 77 percent of Field Gathering and Processing volumes are processed through the Townsend, Blair Creek and Gordondale Facilities located in the liquids rich Montney resource play.

Townsend

AltaGas completed construction of the Townsend Facility in mid-2016, which is a 198 Mmcf/d shallow cut gas processing facility located approximately 100 km north of Fort St. John and 20 km southeast of AltaGas' Blair Creek Facility. Painted Pony has reserved all of the firm capacity under a 20-year take-or-pay agreement.

A 25 km gas gathering line connects the Blair Creek field gathering area to the Townsend Facility and Painted Pony has reserved all of the firm service under a 20-year take-or-pay agreement. In addition, two liquids egress lines totaling approximately 30 km connect the Townsend Facility to a truck terminal on the Alaska Highway. Painted Pony has reserved all firm liquids capacity under a 20-year take-or-pay agreement.

Townsend Phase 2

AltaGas is developing Townsend Phase 2, an expansion of the existing Townsend Facility. For further details see "Development of the Gas Business of AltaGas" sub-heading under "General Development of AltaGas' Business".

Blair Creek

AltaGas owns 100 percent of the Blair Creek Facility which has processing capacity of 83 Mmcf/d of natural gas. AltaGas operates the facility which is located approximately 140 km northwest of Fort St. John, British Columbia.

The facility processes gas gathered from Painted Pony and Tourmaline Oil Corp under long term take-or-pay contracts. The plant is equipped with liquids extraction facilities to capture the NGL's value for the producer.

Gordondale

AltaGas owns 100 percent of the Gordondale Facility which has processing capacity of 150 Mmcf/d of natural gas. AltaGas operates the facility which is located in the Gordondale area of the Montney reserve area approximately 100 km northwest of Grande Prairie, Alberta.

The facility processes gas gathered from Birchcliff Energy Ltd.'s Gordondale Montney development under a long term take-or-pay contract. The plant is equipped with liquids extraction facilities to capture the NGL's value for the producer.

FG&P Other Operating Area's

AltaGas' remaining 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. AltaGas currently conducts business with more than 80 producers in its Field Gathering and Processing operating areas.

Field Gathering and Processing - Contracts

AltaGas gathers and processes natural gas under contracts with natural gas producers. Currently, there are approximately 170 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 construction or acquisition.

Fee Structure

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 and at several facilities on a take-or-pay basis.

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. The majority of contracts in place at December 31, 2016 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 often 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 - Competition

AltaGas competes with other midstream entities operating in the WCSB. In 2016, AltaGas processed an average of 312 Mmcf/d, which was approximately 2 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 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.

AltaGas currently also owns the EDS and JFP NGL pipelines. Nova Chemicals has exercised its option to purchase these pipelines in March 2017.

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

One of the key functions of the energy services business is to support AltaGas' infrastructure businesses. The energy services group, among other things, contracts supply and shrinkage gas for AltaGas' extraction facilities, manages storage capacity, contracts and resells capacity on AltaGas' transmission pipelines and provides natural gas control services to balance natural gas flow. The energy services group also markets natural gas for certain Field Gathering and Processing customers.

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, retail and utility gas users and manages the third-party pipeline transportation requirements for many of its gas marketing customers.

Gas Business – Energy Export

In December 2015, AltaGas signed a sublease and related agreements with Ridley Terminals for the construction of the Ridley Island Propane Export Terminal, which is to be designed to ship up to 1.2 million tonnes of propane per annum. A positive final investment decision was made on the Ridley Island Propane Export Terminal in January 2017 and construction is expected to begin in the first quarter of 2017. AltaGas anticipates having physical volumes equal to approximately 50 percent of the 1.2 million tonnes. The remaining 50 percent is slated to be supplied by producers and aggregators in Western Canada. AltaGas expects to underpin at least 40 percent of the Ridley Island Propane Export Terminal throughput under tolling arrangements with producers and other suppliers. In May 2016, AltaGas entered into a Memorandum of Understanding with Astomos contemplating a multi-year agreement, for the purchase of at least 50 percent of the 1.2 million tonnes of propane available to be shipped from the Ridley Island Propane Export Terminal each year, the key commercial terms of which have been settled. Commercial discussions with Astomos and several other third party offtakers for further capacity commitments are proceeding. AltaGas has offered a third party the option to take an equity position of up to 30 percent in the Ridley Island Propane Export Terminal.

AltaGas is also pursuing LPG export opportunities through its ownership interest in Petrogas. Petrogas owns the Ferndale Terminal, which is operated by AltaGas. The Ferndale Terminal is capable of handling LPG exports up to 30,000 Bbls/d with 750,000 Bbls of on-site storage capacity. The Ferndale Terminal has rail, truck and pipeline capability and is connected to two local refineries. The Ferndale Terminal was reconfigured to handle propane with the first propane shipments commencing in April 2015. In addition, Petrogas also has a logistics network consisting of over 1,800 rail cars and 24 rail and truck terminals in Canada and the United States. Petrogas' major terminal and owned and leased storage facilities are located in key energy hubs including Fort Saskatchewan, Alberta, Sarnia, Ontario, Griffith, Indiana, Conway, Kansas and Mt. Belvieu, Texas.

POWER BUSINESS

AltaGas' Power business contributed revenue of $575 million for the year ended December 31, 2016 (2015 - $476 million), representing approximately 23 percent (2015 – 20 percent) of AltaGas' total revenue before Corporate segment and intersegment eliminations.

The Power business is engaged in the generation and sale of electricity and ancillary services in Alberta, British Columbia, California, Colorado, Michigan and North Carolina. At December 31, 2016, AltaGas had 1,708 MW of installed power capacity, as more particularly set forth in the below table.

Facility	Interest (%)	Capacity (MW)	Type	Geographic Region	Contracted Expiry Date
Blythe	100	507	Gas-fired	California, U.S.	2020
Tracy	100	330	Gas-fired	California, U.S.	2022
Forrest Kerr	100	195	Hydro	British Columbia, Canada	2074
Bear Mountain	100	102	Wind	British Columbia, Canada	2034
Hanford	100	97	Gas-fired	California, U.S.	2022
Henrietta	100	96	Gas-fired	California, U.S.	2022
Brush II	100	70	Gas-fired	Colorado, U.S.	2019
McLymont	100	66	Hydro	British Columbia, Canada	2075
Ripon	100	49.5	Gas-fired	California, U.S.	2018
Pomona	100	44.5	Gas-fired	California, U.S.	Merchant
Craven	50	24	Biomass	California, U.S.	2017
Pomona Energy Storage	100	20	Storage	California, U.S.	2027
Volcano	97	16	Hydro	British Columbia, Canada	2074
Cogeneration I	100	15	Gas-fired	Alberta, Canada	Merchant
Cogeneration II	100	15	Gas-fired	Alberta, Canada	Merchant
Cogeneration III	100	15	Gas-fired	Alberta, Canada	Merchant
Busch Ranch	50	14.5	Wind	Colorado, U.S.	2037
Grayling	30	11.1	Biomass	Michigan, U.S.	2027
Parkland	100	10	Gas-fired	Alberta, Canada	Merchant
Bantry	100	7	Gas-fired	Alberta, Canada	Merchant
Gordondale	100	3.4	Gas-fired	Alberta, Canada	Merchant
Total		**1,708**			

AltaGas expects additional growth in the Power business, which will be driven by advancing AltaGas' significant and growing portfolio of renewable energy projects and pursuing further gas-fired generation opportunities. For the coming years, AltaGas has approximately 1,253 MW of gas-fired power generation projects in development of which 1,163 MW of generation is targeted for California and 90 MW for Canada.

The following chart provides a summary of the volumes sold, renewable capacity factor and contracted conventional equivalent availability factor for the last two years.

	2016	2015
Renewable power sold (GWh)	**1,551**	1,300
Conventional power sold (GWh)	**1,950**	4,408
Renewable capacity factor (%)	**39.1**	35.4
Contracted conventional equivalent availability factor (%) (1)	**97.3**	96.9

Note:

(1) Calculated as the availability factor contracted under long-term tolling arrangements adjusted for occasions where partial or excess capacity payments have been added or deducted.

Gas-Fired Generation

In northern California, the Corporation is focused on owning generating assets in locally constrained areas near load pockets as local resource adequacy needs result in more opportunities for expansion and re-contracting. On November 30, 2015, AltaGas acquired three Northern California gas-fired power assets with total generating capacity of 523 MW, located in the San Joaquin Valley. All three assets are fully contracted through 2022 with PG&E under PPAs which are structured as tolling arrangements for 100 percent of facility energy, capacity and ancillary services. Earlier in 2015, AltaGas acquired Ripon, which is also contracted with PG&E until May 31, 2018. AltaGas is currently in the preliminary development stages to increase generation capacity at Ripon.

In southern California, the 507 MW 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 revenue from the facility is derived from being available to produce and not from 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 to SCE and the transmission grid operated by the CAISO via a 67-mile transmission line owned by the Blythe Energy Center. The facility also has the capability of directly connecting to both the California and Arizona markets and is connected to the El Paso gas supply. 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 additional land to provide further opportunities to expand. These sites offer potential contracting opportunities for future projects with multiple creditworthy utilities and regional municipalities in California and adjacent states, as well as corporations. 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. In addition, AltaGas acquired Pomona in early 2015, which is strategically located in the East Los Angeles basin load pocket. AltaGas is continuing to work on incremental development of either additional energy storage or incremental gas fired generation at the existing Pomona facility. In the first quarter of 2016, AltaGas, through its subsidiary AltaGas Pomona Energy Inc., submitted an application with the California Energy Commission to repower the Pomona facility to a flexible, fast ramping peaking facility under the small power plant exemption process. It is anticipated that the California Energy Commission will complete the application review process in 2017, which will be followed by City of Pomona and local air district permitting processes.

AltaGas currently has 45 MW of cogeneration capacity in Alberta. Each of the three cogeneration facilities can generate 15 MW of power 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.

Battery Storage

AltaGas constructed, owns and operates the Pomona Energy Storage Facility, a lithium-ion battery storage facility. The Pomona Energy Storage Facility is a 20 MW (80 MWh) facility which entered service on December 31, 2016 and is under contract for its capacity with SCE under a 10-year ESA. Under the terms of the ESA, AltaGas will provide SCE with 20 MW of resource adequacy capacity for a continuous four hour period, which represents the equivalent of 80 MWh of energy discharging capacity. AltaGas will receive fixed monthly resource adequacy payments under the ESA and will retain the rights to earn additional revenue from the energy and ancillary services provided by the lithium-ion batteries, which will be sold on a merchant basis into the CAISO.

Run-of-River Hydroelectric Generation

In 2014, AltaGas commissioned the 195 MW Forrest Kerr and 16 MW Volcano Creek facilities and in 2015, AltaGas commissioned the 66 MW McLymont Creek facility. The Northwest Hydro Facilities have a combined generating capacity of approximately 277 MW and 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 Hydro Facilities, ensuring a cooperative and mutually beneficial relationship between the Tahltan First Nation and AltaGas. In addition, AltaGas entered into an agreement with BC Hydro to contribute to the development of the NTL. The Northwest Hydro Facilities are the anchor tenant for the NTL.

Earnings from the Northwest Hydro Facilities are impacted by variations in river flow necessary for power generation. Increases in precipitation and snowpack melt in the spring and summer months, create periods of higher water flow resulting in seasonally stronger earnings.

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. 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. 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.

AltaGas indirectly owns a 50 percent interest in a 29 MW wind farm in Colorado (Busch Ranch). Busch Ranch has a 25-year REPA with Black Hills/Colorado Electric Utility Company, LP.

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.

Energy and ancillary services attributes from the Pomona Energy Storage Facility are bid into the CAISO market on a day ahead basis. The CAISO establishes the supply stack based on the bids submitted and matches that to the demand curve based on a full network model which uses the costs of supply and demand for energy at individual nodes across the service area to establish locational marginal pricing. The market is then sorted again in the 15-minute market and on a real time basis to establish the price cleared at the relevant node. Pricing information is published on the CAISO website.

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 Forrest Kerr, McLymont and Volcano Creek are sold at a predetermined price as contracted under the 60-year EPAs with BC Hydro. The EPAs for Forrest Kerr, McLymont, and Volcano Creek are fully indexed to CPI. Power sold from Grayling and Craven is not exposed to market prices and is sold under PPAs that expire August 2027 (with automatic one year renewals unless terminated) and December 31, 2017, respectively. Ripon is contracted by PG&E under a PPA until May 31, 2018. Brush II is contracted by Tri-State Generation and Transmission Association, Inc. until December 31, 2019. Tracy, Hanford and Henrietta are all fully contracted with PG&E under PPAs until October 31, 2022 for Tracy and December 31, 2022 for Hanford and Henrietta.

UTILITIES BUSINESS

AltaGas' Utilities business contributed revenue of $1.1 billion for the year ended December 31, 2016 (2015 - $1.1 billion), representing approximately 44 percent (2015 – 45 percent) of AltaGas' total 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 in Alberta, PNG in British Columbia, Heritage Gas in Nova Scotia and a one third interest in Inuvik Gas in the Northwest Territories. The Utilities business in the United States is comprised of SEMCO Gas in Michigan, ENSTAR in Alaska 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, regulated utilities are allowed the opportunity to earn regulated rates that provide for recovery of costs and a return on capital from the regulator, which is to reflect a fair rate of return on a regulatory deemed or targeted capital structure applied to an approved regulatory asset value (i.e. rate base). The ability of a regulated utility to recover prudently incurred costs of providing service and earn the regulator-approved rate of return on equity depends on the utility achieving the forecasts established in the rate-setting processes. 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 of service 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 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.

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

The gas utility business of SEMCO Energy 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. In Alaska, rates are set using the results from a historical test year plus known and measurable changes. In Michigan, rates are set using forward test year. In both jurisdictions, 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 average rate base for the Utilities business for the years ended December 31, 2016 and 2015:

	2016	**2015**
Rate base *($ millions)* (1)		
Utilities Canada	790	741
Utilities U.S. (2) (3)	840	851

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, but may differ from the rate base indicated above.

(2) In U.S. dollars.

(3) Reflects SEMCO Energy's 65 percent interest in CINGSA.

The following table summarizes the capital expenditures for the years ended December 31, 2016 and 2015.

	2016	**2015**
($ millions)		
Utilities Canada		
New business	19	35
System betterment and gas supply	39	41
General plant	7	8
Total	65	84
Utilities U.S. (1)		
New business	14	16
System betterment and gas supply	35	55
General plant	4	8
Total	53	79

Note:

(1) In U.S. dollars.

The following table summarizes the nature of regulation applicable to each utility (other than Inuvik Gas):

Regulated Utility	Regulated Authority	% of AltaGas' Consolidated Rate Base as at December 31, 2016	Allowed Common Equity (%)	Allowed ROE (%) 2015	Allowed ROE (%) 2016	Significant Features/ Material Regulatory Development
AUI	AUC	15	41(1)	8.30	8.30(1)	- Distribution rates approved under PBR model, current term 2013 - 2017 - Cost recovery and return on rate base through revenue per customer formula - Additional recovery and return on rate base through capital tracker program
Heritage Gas	NSUARB	15	45	11.00	11.00	- Distribution rates approved under cost of service model - No regulatory lag; earn immediately on invested capital - RDA of up to $50 million - Customer Retention Program approved in September 2016 resulting in a decrease in distribution rates for certain commercial and residential customers
PNG	BCUC	11				- Distribution rates approved under cost of service model - Permanent rates approved for test year 2017 in the 2016/17 Revenue Requirement Application - Protected from weather related volatility through revenue stabilization adjustment account - Next rate case to be filed in Q4 2017 for test years 2018 and 2019
PNG West			46.5	9.50	9.50	
PNG(NE) Fort St. John /Dawson Creek			41	9.25	9.25	
PNG(NE) Tumbler Ridge			46.5	9.50	9.50	
SEMCO Gas	MPSC	33	49	10.35	10.35	- Distribution rates approved under cost of service model - Use of projected test year for rate cases with 10 month limit to issue a rate order, ability to seek partial and immediate rate relief, mitigates regulatory lag - Rate rider provides recovery relating to the Main Replacement Program which allows the company to accelerate the replacement of older portions of its system - Last rate case settled in 2011
ENSTAR	RCA	20	51.7	12.55	12.55	- Distribution rates approved under cost of service model using historical test year and allows for known and measurable changes - Permanent rate increase in 2015 of approximately 2.2% over the interim and refundable rate increase approved as part of 2014 base rate case - Interim and refundable rate increase in 2016 of approximately 0.8% until resolution of 2016 rate case. - An additional 1.6% interim and refundable rate increase on total revenues was requested and granted effective August 1, 2016, as part of the June 1, 2016 rate case filing - Requested increase of ~3.9% on total revenues; final rates expected to be set in Q3 2017
CINGSA	RCA	6	50	12.55	12.55	- Distribution rates approved under cost of service model using historical test year and allows for known and measurable changes - Rate case will be filed in 2017 based on 2016 historical test year

Note:
(1) 2013-2016 ROE approved at 8.3%; 2017 ROE approved at 8.5% pursuant to Generic Cost of Capital decision.

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, C&I consumers in more than 90 communities throughout Alberta. At the end of 2016, AUI served approximately 79,000 customers. 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, reliable, 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. AUI pursues opportunities to develop service areas not currently served with natural gas.

Operations

AUI's distribution system consists of 21,019 km of pipeline. 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 2016, the total throughput of natural gas delivered to 78,656 end consumer service sites and transported for three producers had a total energy value of approximately 16.8 PJ.

AUI's market consists primarily of residential and small commercial consumers located in smaller population centres or rural areas of Alberta. AUI's revenue by service type for each of the last two years is shown below:

AUI Revenue by Service Type(1)

(%)	**2016**	**2015**
Residential	57.7	56.6
Commercial	21.6	22.6
Rural(2)	17.2	17.0
Demand	3.5	3.8
Total	100.00	100.00

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, 2016, AUI held a total of 74 such franchises and agreements, the majority of which are held with municipalities, with average remaining terms that vary from 3.6 years to perpetual and are renewed from time to time in the ordinary course of AUI's business. The top three municipalities contributing to AUI's total revenue in 2016 were the City of Leduc, Town of Beaumont and Town of Morinville, which collectively accounted for approximately 24 percent of AUI's total revenue and 20 percent of energy delivered in 2016.

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.

Material Regulatory Developments and Applications

With the imminent expiry of the first generation PBR plan, establishing distribution rates for 2013 to 2017, the AUC directed AUI and other regulated Alberta distribution utilities to file applications by March 31, 2017 to establish going-in rates for the second generation of PBR plans, expected to come into effective January 1, 2018 for a five year term.

HERITAGE GAS

Heritage Gas is a greenfield natural gas distribution utility in Nova Scotia with a head office located in Dartmouth, Nova Scotia. Heritage Gas' franchise was granted in 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.

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 across all sectors is oil, with over 50 percent of the market share. 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. Across all sectors, natural gas is currently fourth in market share in Nova Scotia.

Beginning in the winter of 2014, declining propane prices available in Nova Scotia made the energy market serving small commercial customers extremely competitive with some customers choosing to adopt alternate fuels to natural gas, or implement dual fuel options. Heritage Gas expects natural gas pricing will return to a more competitive alternative as propane prices are projected to increase over the coming years and as lower priced natural gas becomes available to Heritage Gas through new pipelines and storage projects. In 2016 Heritage Gas gained approval for a Customer Retention Program from the NSUARB to enable the Company to retain commercial customers through this period of competitive commodity pricing. To date the program has been successful in curtailing the migration of customers to propane. In 2016 Heritage Gas continued to add residential and commercial customers, although at a slower pace than recent years.

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 2016 there were approximately 21,000 potential customer meters of which approximately 7,100 were commercial energy consumers and 13,900 were residential energy consumers with access to the Heritage Gas distribution system. Of the 21,000 potential customer meters, Heritage Gas had approximately 6,500 customer meters activated by December 31, 2016. While the Customer Retention Program is in place, Heritage Gas' expects to focus on increasing penetration levels within its existing network.

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 (%)	**2016**	**2015**
Activated residential	25	25
Activated commercial	42	44
All customers	31	31

Commercial customer penetration rates declined slightly in 2016, as challenging competitive forces limited customer growth while the network coverage area increased.

Operations

Heritage Gas' distribution system consists of approximately 455 km of pipeline mains infrastructure of which approximately 345 km is located in the Halifax Regional Municipality, approximately 60 km is located in Amherst, 40 km in New Glasgow/Pictou area and approximately 10 km is located in Oxford.

Historically Heritage Gas has received much of its natural gas supply from the Sable Offshore Energy project and Encana Corporation's Deep Panuke project off the coast of Nova Scotia. This natural gas supply from the Sable Offshore Energy project is declining with the industry expecting an end of reserves in the 2017-2019 timeframe. In 2016 much of Heritage

Gas' gas supply was delivered via both Maritimes and Northeast US and Canadian pipeline systems, from supply basins offshore Nova Scotia and in the United States and Central and Western Canada.

Heritage Gas purchases gas under negotiated contracts with wholesale gas marketers. During 2016, Heritage Gas entered into gas supply and transportation contracts to ensure security of supply and to provide relative price stability. The gas supply contracts have ending dates ranging from February 28, 2017 to March 31, 2017. Heritage Gas is expecting to transact for its initial supply of gas for the winter of 2017/2018 before the end of February 2017. The transportation agreements have various terms with start dates ranging from April 2016 to November 2017, and end dates ranging from October 2017 to October 2032. The cost of gas purchased is flowed through to the distribution customers and does not impact net income.

In 2014, Heritage Gas executed a 20-year gas storage agreement with Alton Natural Gas Storage L.P., a wholly-owned subsidiary of AltaGas, for storage capacity at the proposed Alton Natural Gas Storage Facility. Construction for this facility is underway and AltaGas currently expects the Alton Natural Gas Storage Facility to be in service in 2020.

Also in 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 November 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.

Material Regulatory Developments and Applications

As previously mentioned, Heritage Gas filed a Customer Retention Program application with the NSUARB on March 2, 2016 requesting a decrease in distribution rates for commercial customers with consumption between 500 and 4,999 GJ per year and allowing for flexible rate increases from time to time for these customers up to previously approved distribution rates, a suspension of depreciation and a 50 percent capitalization rate for operating, maintenance and administrative expenses while the Customer Retention Program is in place. In September 2016, the NSUARB approved Heritage Gas' Customer Retention Program application. The approval included all of the items requested by Heritage Gas as well as a reduction to residential customer rates of $0.50 per GJ for the 2016-2017 and 2017-2018 winter seasons and a return on the deferred depreciation and operating expense balances arising from the Customer Retention Program of 4 percent. Heritage Gas expects that the Customer Retention Program will be in place through to 2021.

In June 2015 Heritage Gas received the NSUARB's decision approving Heritage Gas' application for the treatment, and the recovery, of natural gas storage service costs related to the proposed Alton Natural Gas Storage Facility. Heritage Gas expects this storage service 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.

PNG

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.

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 PNG’s 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 practice.

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 and entered into transportation reservation agreements (TRAs) with two parties to support the PNG looping expansion project. These TRAs provide for cost recovery of development expenses incurred with respect to the project. The TRA with one of the parties was terminated in March 2016 and PNG recovered that party’s share of the project development expenses. The second party amended some terms of its TRA and as part of the amendment also paid back its share of the project development expenses and recoveries of overhead costs to date.

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.

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 of which are presently deactivated).

On December 12, 2014, EDFT executed a 20-year Gas Transportation Service Agreement (GTSA) with PNG for pipeline capacity to supply gas to the DC LNG Project. During 2015, PNG received BCUC approval to assign, novate, and amend the GTSA to provide an option to contract for 80 Mmcf/d of the existing capacity on the Western System and approval to construct and operate an interconnecting pipeline between Kitimat and Douglas Channel to facilitate servicing the GTSA, EDFT and the DC LNG Project. In the first quarter of 2016, the DC LNG Consortium halted development of the DC LNG Project and subsequently terminated its GTSA. PNG continues to seek potential new customers to take over the released capacity in its Western System.

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 pipelines owned by Canadian Natural Resources Limited to obtain supply for the Fort St. John area; 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, 2,204 km of distribution lines and a gas processing plant near Tumbler Ridge with a capacity of 120 10^3m^3 per day.

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

	2016	2015
Deliveries: (PJ)		
Residential	2.5	2.9
Commercial	2.6	2.7
Small industrial	2.4	2.8
Large industrial	1.4	1.0
Total deliveries	8.9	9.4

	2016	2015
Customers at Year End:		
Residential	36,169	35,866
Commercial	5,409	5,383
Small industrial	50	52
Large industrial	2	2
Total customers	41,630	41,303

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 2036).

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, the District of Taylor and the City of Dawson Creek for 21-year terms, expiring in 2018, 2033, and 2036, respectively. PNG(NE) also has an operating agreement with the Village of Pouce Coupe which expired on December 31, 2016. An interim operating agreement is in place as PNG(NE) is in the process of finalizing a new franchise agreement with this municipality. 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.

Seasonality

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.

Inuvik Gas and Ikhil Joint Venture

Inuvik Gas is a corporation equally owned one third each by an AltaGas subsidiary, the Inuvialuit Petroleum Corporation, and ATCO Midstream NWT Ltd. The Ikhil Joint Venture is owned one third each by an AltaGas subsidiary, Inuvialuit Petroleum Corporation and ATCO Midstream NWT Ltd. 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. On December 7, 2016, Inuvik Gas notified the Town of Inuvik of its intention to terminate the gas distribution franchise agreement effective December 2018. Inuvik Gas will work with the Town of Inuvik over the course of the remaining term to transition ownership to the Town of Inuvik.

At the end of 2016 Inuvik Gas provided service to approximately 900 residential and commercial customers.

SEMCO ENERGY

SEMCO Energy’s head office is located in Port Huron, Michigan. 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 2016 consolidated 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, distribute and sell natural gas and related gas distribution services to residential, C&I customers and is SEMCO Energy's largest business segment.

SEMCO GAS

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

The average number of customers at SEMCO Gas has increased by an average of approximately 0.9 percent annually during the past three years (with an increase of 1.0 percent in 2016). 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.

Operations

The SEMCO Gas natural gas transmission and delivery system in Michigan includes approximately 151 miles of gas transmission pipelines and 6,142 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.

SEMCO Gas has access to natural gas supplies throughout the United States and Canada via interstate and intrastate pipelines in and near Michigan. To provide gas to SEMCO Gas sales customers, SEMCO Gas has negotiated standard terms and conditions for the purchase of natural gas under the North American Energy Standards Board (NAESB) form of agreement with a variety of suppliers.

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

	2016	2015
Deliveries: (MDth)		
Residential	23,193	24,592
Commercial	12,785	12,940
Transport	20,347	19,683
Gas Customer Choice(1)	3,208	3,067
Total deliveries	59,533	60,282

	2016	2015
Customers at Year End:		
Residential	255,906	254,964
Commercial	23,399	23,176
Transport	256	251
Gas Customer Choice(1)	20,469	18,782
Total customers	300,030	297,173

Note:
(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.

Material Regulatory Developments and Approvals

On December 15, 2016, SEMCO Gas filed an application with the MPSC seeking approval to construct, own, and operate the MCP. For further details see sub-heading "Development of the Utilities Business of AltaGas" under "General Development of AltaGas' Business".

Environmental

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 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.

As of December 31, 2016, SEMCO Gas has completed the investigation and remediation at the two MGP sites it was responsible for and has received No Further Action (NFA) letters from the Michigan Department of Environmental Quality for both sites. SEMCO Gas will continue to monitor these sites in the future as required by the NFA letters. As a result of the NFA letters received to date, SEMCO Gas believes that the likelihood of any further liability at either of these sites is remote. However, if applicable environmental laws change that require further investigation and remediation to be performed at the sites in the future, SEMCO Gas could incur a material liability. This liability would be offset by a corresponding regulatory asset.

In accordance with an MPSC accounting order, SEMCO Gas’ environmental investigation and remediation costs associated with these MGP sites are deferred and amortized over ten years. Rate recognition of the related amortization expense does not begin until the costs are subject to review by the MPSC in a base rate case. To the extent that any costs are not fully recoverable from customers through regulatory proceedings or from insurance or other potentially responsible persons, these costs would reduce SEMCO Gas' earnings and results of operations.

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.

ENSTAR

In Alaska, ENSTAR distributes natural gas to approximately 143,000 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 1.6 percent annually during the past three years (with an increase of 1.5 percent in 2016). 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.

Operations

ENSTAR's natural gas delivery system (including SEMCO Energy's Alaska Pipeline Company) includes approximately 430 miles of gas transmission pipelines and 3,045 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 are 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 as has the amount of deliverability available from Cook Inlet producers. The majority of ENSTAR's gas supply and deliverability needs are provided by long term contracts with Cook Inlet producers into 2023.

In order to better address the seasonal deliverability demands of ENSTAR's customers, SEMCO Energy 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. The LNG export plant re-opened in April 2014 and in February 2016, it received a two-year LNG export license to export approximately 40 Bcf from the Cook Inlet area. In light of the relative stability of its gas supply, ENSTAR did not oppose the issuance of this license.

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

	2016	2015
Deliveries: (Mmcf)		
Residential	17,509	18,283
Commercial	11,853	12,463
Transport	27,963	24,968
Total deliveries	57,325	55,714

	2016	2015
Customers at Year End:		
Residential	129,949	128,093
Commercial	12,680	12,590
Transport	22	17
Total customers	142,651	140,700

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.

Forecasted volumes 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.

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.

CINGSA provides firm gas storage service to ENSTAR and to three Cook Inlet area electric utilities and provides interruptible gas storage service to ENSTAR and five other customers. ENSTAR has subscribed for approximately 78 percent of CINGSA's initial capacity and approximately 66 percent of the associated initial gas injection and withdrawal capability, with the remainder of the capacity and injection and withdrawal capability split among the other customers.

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 its other customers as described above in the Cook Inlet area of Alaska.

Material Regulatory Developments and Approvals

In 2013, CINGSA detected higher than expected pressure during its biannual shut-in. CINGSA determined that it had encountered a pocket of gas that was at or near the initial reservoir pressure. Following extensive analysis, CINGSA has determined that the pocket of found gas it discovered totalled approximately 14.5 Bcf. In August 2015, CINGSA entered into a stipulation with most of its customers regarding the disposition of the found gas. Hearings before the RCA were held in September 2015. On December 4, 2015, the RCA issued an order that denied the stipulation, allowed CINGSA to sell up to 2 Bcf of the gas and required that approximately 87 percent of the net proceeds of any such sale be allocated to CINGSA's firm customers. On January 4, 2016, CINGSA appealed the RCA decision to the Superior Court of Alaska. The matter is in the briefing stage at this time.

CORPORATE SEGMENT

The Corporate segment consists of general corporate investments (including investments in other public companies) and other revenue and expense items, such as general corporate overhead and interest expense, which are not directly attributable to AltaGas' operating business segments. For the year ended December 31, 2016, the revenue for the Corporate segment was $nil excluding intersegment eliminations (2015 – $10 million) and as at December 31, 2016, AltaGas held approximately 3 percent of the common shares of Alterra Power Corp. and approximately 4 percent of the common shares of Painted Pony through the corporate segment.

CAPITAL STRUCTURE

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share 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. At December 31, 2016 AltaGas had 166,906,833 outstanding Common Shares, 5,511,220 outstanding Series A Shares, 2,488,780 outstanding Series B Shares, 8,000,000 outstanding Series C Shares, 8,000,000 outstanding Series E Shares, 8,000,000 outstanding Series G Shares and 8,000,000 outstanding Series I Shares. On February 3, 2017, AltaGas issued 80,710,000 Subscription Receipts pursuant to the Offering and Concurrent Private Placement, such Subscription Receipts will be automatically exchanged for Common Shares upon the closing of the WGL Acquisition as more particularly described below under "Subscription Receipts". On February 22, 2017, AltaGas issued 12,000,000 Series K 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 June 6, 2016, AltaGas closed a public offering of 14,685,000 Common Shares, on a bought deal basis, at an issue price of $30 per common share, for total gross proceeds of approximately $440 million.

Preferred Shares [1]

	Current Yield	Annual dividend per share[2]	Redemption price per share	Redemption and conversion option date[3][4]	Right to convert into[4]
Series A Shares [5]	3.38%	$0.845	$25	September 30, 2020	Series B Shares
Series B Shares [6]	Floating [6]	Floating [6]	$25	September 30, 2020 [7]	Series A Shares
Series C Shares [8]	4.40%	US$1.10	US$25	September 30, 2017	Series D Shares
Series E Shares [5]	5.00%	$1.25	$25	December 31, 2018	Series F Shares
Series G Shares [5]	4.75%	$1.1875	$25	September 30, 2019	Series H Shares
Series I Shares [9]	5.25%	$1.3125	$25	December 31, 2020	Series J Shares
Series K Shares [10]	5.00%	$1.25	$25	March 31, 2022	Series L Shares

Notes:

(1) The table above only includes those series of Preferred Shares that are currently issued and outstanding. The Corporation is authorized to issue up to 8,000,000 of each of Series D Shares, Series F Shares, Series H Shares, Series J Shares and Series L Shares, subject to certain conditions, upon conversion by the holders of the applicable currently issued and outstanding series of Preferred Shares noted opposite such series in the table on the applicable conversion option date. If issued upon the conversion of the applicable series of Preferred Shares, Series D Shares, Series F Shares, Series H Shares, Series J Shares and Series L Shares are also redeemable for $25.50 on any date after the applicable conversion option date, plus all accrued but unpaid dividends to, but excluding the date fixed for redemption.

(2) The holders of Series A, C, E, G, I and K Shares are entitled to receive a cumulative quarterly fixed dividend as and when declared by the Board of Directors. The holders of Series B Shares are entitled to receive a quarterly floating dividend as and when declared by the Board of Directors. If issued upon the conversion of the applicable series of Preferred Shares, the holders of Series D Shares, Series F Shares, Series H Shares, Series J Shares and Series L Shares will be entitled to receive a quarterly floating dividend as and when declared by the Board of Directors.

(3) AltaGas may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter.

(4) The holder will have the right, subject to certain conditions, to convert their preferred shares of a specified series into Preferred Shares of that other specified series as noted in this column of the table on the applicable conversion option date and every fifth anniversary thereafter.

(5) Holders will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent (Series A Shares), 3.17 percent (Series E Shares), and 3.06 percent (Series G Shares).

(6) Holders of Series B Shares will be entitled to receive cumulative quarterly floating dividends, which will reset each quarter thereafter at a rate equal to the sum of the then 90-day government of Canada Treasury Bill rate plus 2.66 percent. Each quarterly dividend is calculated as the annualized amount multiplied by the number of days in the quarter, divided by the number of days in the year. Commencing December 31, 2016, the floating quarterly dividend rate for Series B Shares is $0.19541 per share for the period starting December 31, 2016 to, but excluding, March 31, 2017.

(7) Series B Shares can be redeemed for $25.50 per share on any date after September 30, 2015 that is not a Series B conversion date, plus all accrued and unpaid dividends to, but excluding the date fixed for redemption.

(8) Holders of Series C Shares will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the sum of the U.S. Government Bond Yield on the applicable rate calculation date plus 3.58 percent.

(9) Holders will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the then five-year Government of Canada bond yield plus 4.19 percent, provided that, in any event, such rate shall not be less than 5.25 percent per annum.

(10) Holders will be entitled to receive cumulative quarterly fixed dividends, which will reset on the redeemable and conversion option date and every fifth year thereafter, at a rate equal to the then five-year Government of Canada bond yield plus 3.80 percent, provided that, in any event, such rate shall not be less than 5.00 percent per annum.

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 parity with Preferred Shares of every other series with respect to accumulated dividends and return of capital and the holders of Preferred Shares will rank prior to the holders of Common Shares and any other shares of AltaGas ranking junior to the Preferred Shares with respect to the payment of dividends and 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 currently issued and, as applicable, outstanding: (i) Series A Shares and the Series B Shares, reference should be made to the articles of amendment of AltaGas filed August 8, 2010 and the prospectus supplement of AltaGas dated August 11, 2010; (ii) Series C Shares and the Series D Shares, reference should be made to the articles of amendment of AltaGas filed June 1, 2012 and the prospectus supplement of AltaGas dated May 30, 2012; (iii) Series E Shares and Series F Shares, reference should be made to the articles of amendment of AltaGas filed December 9, 2013 and the prospectus supplement of AltaGas dated December 6, 2013; (iv) Series G Shares and Series H Shares, reference should be made to the articles of amendment of AltaGas filed June 27, 2014 and the prospectus supplement of AltaGas dated June 25, 2014; (v) Series I Shares and Series J Shares, reference should be made to the articles of amendment of AltaGas filed November 17, 2015 and the prospectus supplement of AltaGas dated November 16, 2015 ; and (vi) Series K Shares and Series L Shares, reference should be made to the articles of amendment of AltaGas filed February 15, 2017 and the prospectus supplement of AltaGas dated February 15, 2017. Each of the articles of amendment and prospectus supplements described herein has been filed with, and may be retrieved from, SEDAR at www.sedar.com.

Medium Term Notes

AltaGas has issued senior unsecured notes in the form of MTNs. On April 7, 2016, AltaGas issued $350 million of MTNs with a coupon rate of 4.12 percent and maturity date of April 7, 2026. Details with respect to the issued and outstanding MTNs can be found in Note 13 to AltaGas' consolidated financial statements as at and for the year ended December 31, 2016 filed on SEDAR at www.sedar.com. The MTNs are not listed or quoted on any exchange.

Subscription Receipts

On February 3, 2017, AltaGas closed both: (a) a public offering of 67,800,000 Subscription Receipts, on a bought deal basis, at an issue price of $31.00 per Subscription Receipt, for total gross proceeds of approximately $2.1 billion (the Offering); and (b) a private placement of 12,910,000 Subscription Receipts to OMERS, the pension plan for Ontario's municipal employees, at an issue price of $31.00 per Subscription Receipt, for total gross proceeds of $392.2 million (after deducting a capital commitment fee payable to OMERS in connection therewith) (the Concurrent Private Placement). The Subscription Receipts entitle the holders thereof to receive, without payment of additional consideration or further action, one common share of AltaGas upon the closing of the WGL Acquisition. See "General Development of AltaGas' Business – Recent Developments" for details on the WGL Acquisition.

The Proceeds are being held in escrow until the earlier of the delivery of the Escrow Release Notice and Direction and the Termination Time by Computershare Trust Company of Canada, as subscription receipt agent, together with accrued interest thereon, and deposited or invested, as the case may be, in accordance with the Subscription Receipt Agreement provided that Dividend Equivalent Payments may be made therefrom.

While the Subscription Receipts remain outstanding, holders thereof will be entitled to receive payments per Subscription Receipt equal to the per Common Share cash dividends, if any, declared by AltaGas on the Common Shares in respect of all record dates for such dividends occurring from February 3, 2017 to, but excluding, the last day on which the Subscription Receipts remain outstanding, to be paid to holders of Subscription Receipts concurrently with the payment date of each such dividend on the Corporation's outstanding Common Shares, paid first out of any interest credited or received on the Escrowed Funds and then as a refund of a portion of the offering price, net of any applicable withholding taxes (any such payment, a Dividend Equivalent Payment). The record date for each Dividend Equivalent Payment will be the same as the record date for dividends declared on the Common Shares.

In the event that the Termination Time occurs after a dividend has been declared on the Common Shares but before the record date for such dividend, holders of Subscription Receipts will receive, as part of the Termination Payment, a pro rata Dividend Equivalent Payment in respect of such dividend declared on the Common Shares based on the ratio of the time between (i) the date of the prior Dividend Equivalent Payment (or, if none, February 3, 2017) and the Termination Time, to (ii) the date of the prior Dividend Equivalent Payment (or, if none, the prior payment date for dividends on the Common Shares) and the dividend payment date for the dividend so declared. If the Termination Time occurs on a record date or following a record date but on or prior to the payment date, holders will be entitled to receive the full Dividend Equivalent Payment.

EMPLOYEES

In June 2016, AltaGas completed a restructuring that reduced its total non-utility workforce by approximately 10 percent.

At December 31, 2016 there were 1,632 individuals employed by AltaGas.

Gas	300
Power	115
Utilities	1,016
Corporate	201
Total	**1,632**

DIRECTORS AND OFFICERS

As at February 17, 2017: (i) the directors and executive officers of AltaGas Ltd., as a group, owned beneficially, directly or indirectly, or exercised control or direction over 3,066,278 of the outstanding Common Shares, or approximately 1.8 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 1,966,750 Common Shares; and (iii) 168,168,409 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 is currently nine, of which eight are independent directors.

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

The following table sets forth the names of the Directors of AltaGas Ltd. on February 17, 2017, 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
Victoria A. Calvert (1) Calgary, Alberta, Canada Director	Victoria Calvert is the Community Service Learning (CSL) Facilitator for Mount Royal University (MRU) in Calgary, and a Professor of Entrepreneurship and International Business at the Bissett School of Business at MRU, where she has taught since 1988. She has consulted for more than 30 years, and published extensively regarding community engagement. Research interests included developing strategies for institutional and community partnerships, Global Service Learning, and structuring CSL for optimal stakeholder impact.	November 1, 2015

Name of Director, Municipality of Residence and Position	Principal Occupation During the Past Five Years	Director Since
David W. Cornhill (2) Calgary, Alberta, Canada Chairman of the Board	David Cornhill is Chairman of the board of directors of AltaGas, a position he has held since AltaGas Services' (AltaGas' predecessor) inception on April 1, 1994. Mr. Cornhill is a founding shareholder and director of AltaGas Services, and was Chief Executive Officer from April 1, 1994 to April 15, 2016. Prior to forming AltaGas Services Inc., Mr. Cornhill served in the capacities of Vice President, Finance and Administration, and Treasurer at Alberta and Southern Gas 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 is an independent businessman. He was the President of ALE Energy Inc., a private consulting company, from January 2005 through December 2015. 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
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
Phillip R. Knoll (1) Halifax, Nova Scotia, Canada Director	Mr. Knoll is a Professional Engineer and the President of Knoll Energy Inc. Mr. Knoll previously was CEO of Corridor Resources Inc. from Oct 2010 to Sept 2014. Up to July 2004 he held roles that included Group Vice President, Duke Energy Gas Transmission, Chair, Management Committee and President for Maritimes & Northeast Pipeline, and held senior roles at Westcoast Energy Inc., TransCanada Pipelines Limited and Alberta Natural Gas Company Ltd. Mr. Knoll was a director, and Audit Committee member, of AltaGas Utility Group Inc. from 2005 to 2009.	November 1, 2015
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

Name of Director, Municipality of Residence and Position	Principal Occupation During the Past Five Years	Director Since
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) Mr. Cornhill is not considered to be an independent director by virtue of having been the CEO of AltaGas up to April 15, 2016.
(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 CCAA, 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 CCAA. 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.

AltaGas has four committees of the Board of Directors: (1) Audit, (2) Governance, (3) Human Resources and Compensation (HRC) and (4) Environment, Occupational Health and Safety (EOH&S). The members of each of these committees, as of December 31, 2016, are identified below:

Director	Audit Committee	Governance Committee	HRC Committee	EOH&S Committee
Catherine M. Best	✓		✓	
Victoria A. Calvert		✓		
David W. Cornhill				
Allan L. Edgeworth	✓			Chair
Daryl H. Gilbert			Chair	✓
Robert B. Hodgins	Chair	✓		
Phillip R. Knoll[1]				✓
David F. Mackie		✓	✓	
M. Neil McCrank		Chair		✓

Notes:
(1) Mr. Knoll has been appointed to the Audit Committee effective January 1, 2017.

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 M. Harris Calgary, Alberta, Canada President and Chief Executive Officer	President and Chief Executive Officer of AltaGas from April 16, 2016. President and Chief Operating Officer of AltaGas from January 2015 to April 15, 2016. 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 and Senior Vice President of Engineering, Procurement and Construction of NRG Energy Inc. from November 2006 to March 2009.
Timothy W. Watson Calgary, Alberta, Canada Executive Vice President and Chief Financial Officer	Executive Vice President and Chief Financial Officer of AltaGas from November 2015. Executive Vice President of AltaGas from March 2015 to October 2015. Head and Managing Director, Canadian Energy and Power Investment Banking at Merrill Lynch Canada Inc. from September 2010 to January 2015. Managing Director in Energy Investment Banking at CIBC World Markets in Calgary from February 2007 to July 2010. Managing Director in Energy Investment Banking with RBC Capital Markets in Calgary, Houston and San Francisco from 2001 to January 2007, and prior to that, various investment banking positions with RBC Capital Markets in Toronto and Calgary from 1990 to 2000.
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.
Corine R.K. Bushfield *Airdrie, Alberta, Canada* *Executive Vice President,* *Chief Administrative Officer*	Executive Vice President, Chief Administrative Officer of AltaGas from December 2016. Senior Vice President and Chief Financial Officer of Long Run Exploration Ltd. from March 2013 to September 2016. Vice President and Assistant Controller of Encana Corporation from 2010 to March 2013.
Randy W. Toone Calgary, Alberta, Canada Executive Vice President, Commercial and Business Development	Executive Vice President, Commercial and Business Development of AltaGas from December 2016. Chief Operating Officer of CSV Midstream Solutions from July 2014 to November 2016. Country Manager of TAG Oil Ltd. from May 2013 to June 2014. President Utilities of AltaGas from December 2012 to April 2013. President Gas of AltaGas February 2012 to December 2012. Co-President Gas of AltaGas from December 2010 to January 2012.
Bradley B. Grant Calgary, Alberta, Canada Vice President and General Counsel	Vice President and General Counsel of AltaGas from May 2015. Partner with the law firm Stikeman Elliott LLP from January 2004 to May 2015. Associate with the law firm Stikeman Elliott LLP from July 1997 to December 2003. Student-at-Law with the law firm of Stikeman Elliott LLP from June 1996 to July 1997.

Name of Officer, Municipality of Residence and Position with AltaGas Ltd.	Principal Occupation During the Past Five Years
Kent E. Stout Airdrie, Alberta, Canada Senior Vice President Organizational Development	Senior Vice President Organizational Development from December 2016. Vice President Corporate Resources of AltaGas from 2002 to November 2016. Director Human Resources from 1999 to 2002.
John D. O'Brien Jr. Dallas, Texas, U.S. President and Chief Operating Officer of AltaGas Services (U.S.) Inc.	President and Chief Operating Officer of AltaGas Services (U.S.) Inc. (ASUS) from April 16, 2016. President of ASUS from May 1, 2015 to April 15, 2016. Executive Vice President, Public Policy and External Affairs of Energy Future Holdings from October 2011 to April 2015. Senior Vice President, Government and Regulatory Affairs of NRG Energy from March 2007 to September 2011.

AUDIT COMMITTEE

Composition of the Audit Committee

The Committee is currently comprised of Catherine M. Best, Allan L. Edgeworth, Robert B. Hodgins and Phillip R. Knoll. 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 was the President of ALE Energy Inc. from January 2005 through December 2015. 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.

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, is a Chartered Professional Accountant, and is a Chartered Accountant in Ontario and Alberta.

Mr. Knoll is a Professional Engineer and the President of Knoll Energy Inc. Mr. Knoll previously was CEO of Corridor Resources Inc. from Oct 2010 to Sept 2014. Up to July 2004 he held roles that included Group Vice President, Duke Energy Gas Transmission, Chair, Management Committee and President for Maritimes & Northeast Pipeline, and held senior roles at Westcoast Energy Inc., TransCanada Pipelines Limited and Alberta Natural Gas Company Ltd. Mr. Knoll was a director, and Audit Committee member, of AltaGas Utility Group Inc. from 2005 to 2009.

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 2016 and 2015 were as follows:

Category of External Auditor Service Fee		2016		2015
Audit Fees	$	2,140,368	$	2,296,411
Audit-Related Fees[(1)]		293,701		433,206
Tax Fees[(2)]		66,595		80,189
All Other Fees[(3)]		118,190		118,190
Total	$	2,618,854	$	2,927,996

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". During 2016 and 2015, the nature of the services provided included review of prospectuses, systems implementation, acquisitions and dispositions, review of financial statements of AltaGas' joint ventures, research of accounting and audit-related issues, 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. During 2016 and 2015, the nature of the services provided was for tax advice and transfer pricing.

(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. During 2016 and 2015, the nature of the services provided was for translation services.

RISK FACTORS

Set forth below is a summary of certain risk factors relating to AltaGas and the business of AltaGas. Also included below is a summary of certain risks relating to the WGL Acquisition and the business of WGL following closing of the WGL Acquisition. The risks described below are not an exhaustive list of all risks, nor should they be taken as a complete summary of all the risks associated with the applicable business being conducted. Security holders and prospective security holders of AltaGas should carefully review and consider the risk factors set out below as well as all other information contained and incorporated by reference in this AIF before making a decision on investment and should consult their own experts where necessary.

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, among other things, 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 issuances. The Board of Directors has discretion in connection with the price and the other terms of the issue of such additional shares. Any issuance of Common Shares or securities convertible into Common Shares may have a dilutive effect on existing Shareholders.

Market Value of Common Shares and Other Securities

AltaGas cannot predict at what price the Common Shares, Preferred Shares or other securities issued by AltaGas will trade in the future. Common Shares, Preferred Shares and other securities of AltaGas will not necessarily trade at values determined solely by reference to the underlying value of the Corporation's assets. One of the factors that may influence the market price of such securities is the annual yield on such securities. An increase in market interest rates may lead purchasers of securities of AltaGas to demand a higher annual yield and this could adversely affect the market price of such securities. In addition, the market price for securities of AltaGas may be affected by announcements of new developments, changes in AltaGas' operating results, failure to meet analysts' expectations, changes in credit ratings, changes in general market conditions, fluctuations in the market for securities and numerous other factors beyond the control of AltaGas.

Variability of Dividends

The cash available for dividends 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.

Debt Service

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

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

Refinancing Risk

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

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 assigned 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.

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.

Litigation

AltaGas and its various subsidiaries and affiliates are, in the course of their business, subject to lawsuits and other claims. Defence and settlement costs associated with such lawsuits and claims can be substantial, even with respect to lawsuits and claims that have no merit. Due to the inherent uncertainty of the litigation process, the resolution of any particular legal proceeding could have a material adverse effect on the financial position or operating results of AltaGas.

External Stakeholder Relations

AltaGas places great importance on establishing and maintaining positive relationships with its stakeholders, including within the communities in which AltaGas operates, local Aboriginal groups and regulators. There is an increasing level of public concern relating to the perceived effect of natural resources activities, including exploration, development, production, processing and transportation, on certain environmental and social aspects such as air and water quality, noise, dust, land and ecological disturbance and employment and economic development opportunities. Opposition to natural resources activities by communities or Aboriginal groups may ultimately impact permitting, operations, and AltaGas' reputation. Publicity adverse to AltaGas' operations, partners, or others operating in the energy industry generally, could have an adverse effect on AltaGas and its operations. While AltaGas is committed to operating in a socially responsible manner, there can be no assurance that its efforts in this respect will mitigate this potential risk.

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 flow 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 fluctuations 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 wellhead 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.

Electricity and Resource Adequacy Prices

AltaGas' revenue from sales of power, capacity and ancillary services attributes are subject to market factors such as fluctuating supply and demand, which may be affected by weather, customer usage, economic activity and growth factors and this exposure may increase upon termination of existing power purchase arrangements. When a power purchase arrangement expires or is terminated, it is possible that the price received by the power generator or the relevant facility or plant under subsequent selling arrangements may be reduced significantly. It is also possible that power purchase arrangements negotiated after the initial term has expired may not be available at profitable prices that permit the continued operation of the affected facility or plant.

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.

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 and C&I counterparties.

In addition, for non-wholly owned subsidiaries, AltaGas relies on other investors to fulfill their commitments and obligations in respect of the project or facility. Credit risk arises from the potential loss resulting from a counterparty failing to meet its obligations in accordance with the agreed terms. AltaGas may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners and other parties. In the event such entities fail to meet their contractual obligations to AltaGas, such failures may have a material adverse effect on AltaGas' business, financial condition, results of operations and prospects. AltaGas mitigates these increased risks through diversification and a review process of the creditworthiness of their 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.

Changes in Legislation

Environmental and applicable operating legislation may be changed in a manner that 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. There can be no assurance that regulatory and environmental laws or policies and government incentive programs relating to energy infrastructure will not be changed in a manner which adversely affects AltaGas.

Income tax laws relating to AltaGas or its affiliates may be changed in a manner that adversely affects shareholders. The incoming administration of President Trump has included as part of its agenda a potential significant reform of U.S. tax laws which may adversely impact AltaGas' business. The details of the reform have not yet emerged so AltaGas is unable to predict the impact, if any, to its businesses. It is likely that some policies adopted by the new administration will benefit AltaGas and others may have a negative impact. Until the changes are enacted, AltaGas will not know whether the potential reform has a cumulative negative or positive effect on the business of AltaGas.

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.

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. The export and import of energy is also subject to regulatory approvals. Power facilities are subject to regulatory approvals and regulatory changes in tariffs, market structure and penalties. AUI, PNG, Heritage Gas, SEMCO Gas, ENSTAR and CINGSA 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, determining methods of cost recovery and issuing debt. Earnings of AltaGas' regulated utilities may be impacted by: (i) changes in the regulator-approved allowed return on equity and common equity component of capital structure; (ii) changes in rate base; (iii) changes in gas delivery volumes; (iv) changes in the number and composition of customers; (v) variances between actual expenses incurred and forecast expenses used to determine revenue requirements and set customer rates; and (vi) recovery of unplanned costs through rate cases.

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' businesses or that of Petrogas or the energy export business. Such changes could materially impact AltaGas' business, financial position and results of operations.

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.

Aboriginal Land and Rights Claims

Aboriginal peoples have claimed rights to a substantial portion of the lands in Canada. AltaGas operates in territories in which such claims have been advanced. Such claims, if successful, could have a significant adverse effect on natural gas production, the construction of natural gas storage infrastructure in Nova Scotia, the 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 the operation or development of facilities for gathering and processing, energy exports, natural gas distribution, storage, power generation or extraction and transmission.

AltaGas has concluded agreements with many Aboriginal communities and other agreements are in development. These agreements support an approach of active engagement with Aboriginal communities that serves to ensure the identification of issues and facilitates constructive problem-solving. Further, AltaGas has taken a proactive approach to enhance the economic participation of Aboriginal groups in its operations where feasible and reasonable. The agreements and the measures taken by AltaGas strengthen relationships between the parties while respecting the ever evolving regulatory and judicial relationship between Canada's governments and Aboriginal people.

However, AltaGas cannot predict whether future aboriginal land claims and the assertion of other rights will affect its ability to conduct its business and operations as currently undertaken or as may be undertaken in the future in such regions. Furthermore, any failure to reach an agreement, or a conflict or disagreement, with, an Aboriginal group could have a material adverse effect on AltaGas' business, financial condition and results of operations.

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.

Weather and Long Term Wind or Hydrology Data

AltaGas' run-of-river hydroelectric power projects may be subject to significant variations in the river 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 pays rent for its water rights. Significant increases in rental costs in the future or changes in way water rights are granted could have a material adverse effect on the AltaGas' business, operating results, financial condition or prospects.

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. Ice can accumulate on wind turbine blades in the winter months. Extreme cold temperatures and the accumulation of ice on wind turbine blades, caused by a number of factors, including temperature, ambient humidity and wind, can impact the ability of wind turbines to operate effectively and could result in the wind turbine experiencing more down-time potentially reducing the life expectancy of the wind turbine and generation revenue. 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 in which AltaGas' utilities operate. 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.

Sufficiency of Water Supply Reliability for the California Assets

The California power generation facilities utilize water sourced either locally or imported from a different watershed or groundwater basin. While there have been no disruptions of water supplies to any of the facilities in California to date, there is the risk that the facilities in California may not always have an adequate supply of water available to meet their operational needs in the future. Similarly, undeveloped assets in California may also face water supply uncertainty. Other sources of water might become available to the facilities in California to offset, partially or entirely, a potential future water supply shortage. However, the effects of any such potential shortage or inadequacy, including acquiring alternative water supplies such as recycled water, local groundwater or other imports, as well as implementing other technologies designed to reduce the water demands of facilities in California, bear risks and uncertainties as to whether other such sources and technologies will be available or sufficient.

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.

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.

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, state and local 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.

Health and Safety

The ownership and operation of AltaGas’ business is subject to hazards of gathering, processing, transporting, fractionating, storing and marketing hydrocarbon products, including but not limited to: blowouts; fires; explosions; gaseous leaks; migration of harmful substances; hydrocarbon spills; corrosion; and acts of vandalism and terrorism. Any of these hazards can interrupt operations, impact AltaGas’ reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, and cause environmental damage that may include polluting water, land or air.

Further, such ownership and operations carries the potential for liability related to worker health and safety, including the risk of government imposed orders to remedy unsafe conditions and/or potential penalties for contravention of health and safety laws, licenses, permits and other approvals, and potential civil liability. Compliance with health and safety laws (and any future changes) and the requirements of licenses, permits and other approvals are expected to remain material to AltaGas’ business.

Safety has and continues to be, a core value of AltaGas and is integral to how AltaGas operates. AltaGas actively works with industry groups and communities within which it operates to improve safety and AltaGas has appropriate policies, procedures and emergency response plans in place, which AltaGas regularly monitors and evaluates to identify opportunities for improvement in its safety programs. However, no assurances can be given that the occurrence of any of these events or the additional workers' health and safety issues relating thereto will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to AltaGas’ business and operations.

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, fires, floods, explosions, earthquakes and other similar events. Unplanned outages or prolonged downtime for maintenance and repair typically increase operation and maintenance expenses and reduce revenues. 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.

Infrastructure

As utilities infrastructure matures several of AltaGas' utilities have implemented replacement programs to replace older vintage infrastructure and taken other preventative and remedial measures. If certain pipelines and related infrastructure were to become unexpectedly unavailable for delivery of current or future volumes of natural gas because of repairs, damage, spills or leaks, or any other reason, it could have a material adverse impact on financial conditions and results of operation of AltaGas' utility business. Although the cost of infrastructure replacement programs are typically recovered in rates, on-going capital is required to fund such programs. In addition, operating issues resulting from maturing infrastructure such as leaks, equipment problems and incidents, including explosions and fire, could result in legal liability, repair and remediation costs, increased operating costs, increased capital expenditures, regulatory fines and penalties and other costs and a loss of customer confidence. Any liabilities resulting from the occurrence of these events may not be fully covered by insurance or rates.

Dependence on Certain Partners

AltaGas does not operate certain facilities and also co-owns certain facilities with joint venture partners. Failure by the operators of these facilities to operate at the cost or in the manner projected by AltaGas could negatively affect AltaGas' results. AltaGas has entered into various types of arrangements with joint venture partners for the construction, operation and/or ownership of certain facilities. Certain of these partners may have or develop interests or objectives which are different from or even in conflict with the objectives of AltaGas. AltaGas does not have the sole power to direct the business and operations of such facilities and AltaGas faces the risk of being impacted by partners' decisions and by potential disagreements regarding operations and other business decisions. Any such differences could have a negative impact on the success of such facilities. AltaGas is sometimes required, through the permitting and approval process of such facilities, to notify and consult with various stakeholder groups, including landowners, Aboriginal groups and municipalities. Any unforeseen delays in this process may negatively impact the ability of AltaGas to complete any given facility on time or at all.

Climate Change and Carbon Tax

Some of AltaGas' significant facilities may be subject to future provincial and/or federal climate change regulations to manage greenhouse gas emissions. See "Environmental Regulation – International Climate Change Agreements", "Canadian Federal Air and GHG Regulations", "Canadian Provincial GHG Regulations", "U.S. Federal Air and GHG Regulations" and "California GHG Regulations". The direct or indirect costs of compliance with these regulations may have a material adverse effect on AltaGas' business, financial condition, results of operations and prospects. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of greenhouse gas emissions and resulting requirements, it is difficult to predict the impact on AltaGas and its operations and financial condition.

Labour Relations

The operations and maintenance staff at Ripon, Pomona, the Blythe Energy Center, Younger and some employees of AUI, PNG and SEMCO Energy are members of a labour union. Labour disruptions could restrict the ability of Ripon, Pomona, and the Blythe Energy Center to generate power, the ability of Younger 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.

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.

Cyber Security, Information, and Control Systems

AltaGas' infrastructure, technologies and data are becoming increasingly integrated, which creates a risk that failure of one system could lead to failure of another system. Information and control systems by their nature are complex and interdependent. The risk of a cyber-attack targeting the industry is also increasing.

Security breaches of AltaGas' information technology infrastructure, including cyber-attacks and cyber-terrorism, or other failures of AltaGas' information technology infrastructure could result in operational outages, delays, damage to assets, the environment or to AltaGas' reputation, diminished customer confidence, lost profits, lost data (including confidential information), increased regulation and other adverse outcomes, including material legal claims and liability and adversely affect its business operations and financial results.

The Corporation's cyber security strategy focuses on information technology security risk management which includes continuous monitoring, ongoing cyber security communications and training for staff, conducting third-party vulnerability and security tests, threat detection and an incident response protocol. However, there is no assurance that AltaGas will not suffer a cyber-attack or an information technology failure notwithstanding the implementation of this strategy and the measures taken pursuant to that strategy, including as set forth above and the occurrence of any of these cyber events could adversely affect AltaGas' financial condition and results of operations.

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.

RISKS RELATED TO THE ACQUISITION OF WGL

Possible Failure to Realize Anticipated Benefits of the Acquisition of WGL

A variety of factors, including those risk factors set forth herein, may adversely affect the ability to achieve the anticipated benefits of the WGL Acquisition.

Satisfaction of Conditions Precedent to the Acquisition of WGL

The completion of the WGL Acquisition is subject to a number of conditions precedent, certain of which are outside the control of AltaGas or other parties to the Merger Agreement, including obtaining the Regulatory Approvals. There is no certainty, nor can AltaGas provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied.

Pursuant to the Merger Agreement, AltaGas and Merger Sub must use their reasonable best efforts to, among other things, cause the transactions contemplated by the Merger Agreement to be consummated as promptly as reasonably practicable, including taking any and all steps necessary to avoid, eliminate or resolve each and every impediment and obtain all consents under antitrust laws or other applicable laws that may be required by any governmental authority, so as to enable the parties to close the transactions contemplated by the Merger Agreement, including any Remedial Action, provided that AltaGas shall not be required to, in connection with obtaining any consent of any governmental authority (including the Regulatory Approvals) in connection with the Merger Agreement or the transactions contemplated thereby, offer or accept, or agree, commit to agree or consent to, any undertaking, term, condition, liability, obligation, commitment, sanction or other measure (including any Remedial Action) that constitutes a Burdensome Condition. Further, without the prior written consent of AltaGas (which consent may be withheld, conditioned or delayed at AltaGas' sole discretion), WGL shall not, and shall not permit any of its subsidiaries to, in connection with obtaining any consent of any governmental authority in connection with the Merger Agreement or the transactions contemplated thereby, offer or accept, or agree, commit to agree or consent to, any undertaking, term, condition, liability, obligation, commitment, sanction or other measure (including any Remedial Action) that constitutes a Burdensome Condition.

There can be no assurance that in order to satisfy their obligations under the Merger Agreement that AltaGas and Merger Sub will not be required to undertake a Remedial Action that could have a material effect on the business, operations and assets of WGL or AltaGas without it being considered a Burdensome Condition.

Additionally, AltaGas expects that closing of the WGL Acquisition will occur by the end of the second quarter of 2018. However, the Merger Agreement allows the transaction to close as late as July 25, 2018 in certain circumstances and the Merger Agreement could be amended to further extend that date. While during the period prior to closing WGL is to carry on business in the ordinary course, given the potentially long period prior to closing the WGL Acquisition there can be no assurance that the business, operations and assets of WGL may not be adversely affected by intervening events. While it is a condition to closing the WGL Acquisition that WGL not be subject to a material adverse effect, it is possible that the business of WGL could be significantly affected prior to such a condition being breached. During the period prior to closing the WGL Acquisition, AltaGas and Merger Sub will have no right to control or direct the operations of WGL and WGL shall exercise complete unilateral control and supervision over its business operations, subject to the terms of the Merger Agreement and therefore AltaGas will, indirectly be reliant on the business judgment and decisions of the board and management of WGL prior to closing the WGL Acquisition.

Regulatory Risk Related to the Acquisition of WGL

The WGL Acquisition is conditional upon, among other things, all waiting periods (and any extensions thereof) applicable to the WGL Acquisition under the HSR Act having expired or been terminated and the receipt of all Regulatory Approvals. A substantial delay in obtaining satisfactory approvals or the imposition of unfavourable terms or conditions in the approvals could have a material adverse effect on AltaGas' ability to complete the WGL Acquisition and on AltaGas' or WGL's business, financial condition or results of operations. In addition, changes in laws or regulations, including tax laws, in the jurisdictions in which AltaGas, WGL and their subsidiaries operate could have a negative effect on their respective businesses, financial condition and results of operations, or on the ability of AltaGas to achieve its anticipated benefits from the WGL Acquisition.

Exchange Rate Risk Related to the Acquisition of WGL

As AltaGas anticipates funding a portion of the purchase price of the WGL Acquisition from a combination of Canadian and U.S. dollar denominated securities and credit facilities, and the purchase price of the WGL Acquisition is denominated in U.S. dollars, a significant decline in the value of the Canadian dollar relative to the U.S. dollar at the time of closing of the WGL Acquisition could increase the cost to AltaGas of funding the purchase price of the WGL Acquisition.

AltaGas' consolidated results of operations may be negatively impacted by foreign currency fluctuations. As a result of the WGL Acquisition, a significantly larger portion of AltaGas' revenues will be earned in U.S. dollars. Accordingly, fluctuations in exchange rates between the Canadian and U.S. dollar may have an increased adverse effect on AltaGas' results and financial condition. Future events that may significantly increase or decrease the risk of future movement in the exchange rates for these currencies cannot be predicted.

Possible Failure to Complete the Acquisition of WGL

The WGL Acquisition is subject to normal commercial risk that the WGL Acquisition may not be completed on the terms negotiated or at all. If the WGL Acquisition is not completed prior to the Termination Time, then the Subscription Receipts will be cancelled and the holders of Subscription Receipts will be entitled to receive a refund of their subscription price and any unpaid Dividend Equivalent Payments owing to such holders of Subscription Receipts. The purchaser would not be entitled to participate in any growth in the trading price of the Common Shares. Further, the purchaser would be restricted from using the funds devoted to the acquisition of the Subscription Receipts for any other investment opportunities until the Escrowed Funds are returned to the purchaser. In addition, if closing of the WGL Acquisition does not take place as contemplated, AltaGas could suffer adverse consequences, including the loss of investor confidence. The discovery or quantification of any material liabilities could have a material adverse effect on AltaGas' business, financial condition or future prospects.

Potential Undisclosed Liabilities Associated with the Acquisition of WGL

In connection with the WGL Acquisition, there may be liabilities that AltaGas failed to discover or was unable to quantify in its due diligence which it conducted prior to the execution of the Merger Agreement and which could have a material adverse effect on AltaGas' business, financial condition or future prospects. In addition, AltaGas may be unable to retain existing WGL customers or employees following the WGL Acquisition. Following the closing of the WGL Acquisition, AltaGas will have no right to claim indemnification under the Merger Agreement for any such events.

Integration of WGL

The ability to realize the anticipated benefits of the WGL Acquisition will depend in part on AltaGas successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as on the ability of AltaGas to realize the anticipated growth from integrating WGL's business into AltaGas' current operations following the WGL Acquisition. To effectively integrate WGL into its current operations, AltaGas must establish appropriate operational, administrative, finance, management systems and controls and marketing functions relating to WGL. This will require substantial attention from AltaGas' management team. This diversion of management attention, as well as any other difficulties which AltaGas may encounter in completing the transition and integration process, could have an adverse impact on AltaGas' business, financial condition, results of operations and cash flows. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the ability of AltaGas to achieve all or some of the anticipated benefits of the WGL Acquisition. There can be no assurance that AltaGas will be successful in integrating WGL's operations, or that the expected benefits will be realized.

Increased Indebtedness

If the WGL Acquisition is completed on the terms contemplated in the Merger Agreement, AltaGas anticipates incurring additional debt, including as a result of borrowings under the Bridge Facility, in order to complete the Merger Agreement on the terms contemplated therein. Such borrowings are anticipated to represent a material increase in AltaGas' consolidated indebtedness. Such additional indebtedness will increase AltaGas' interest expense and debt service obligations and may have a negative effect on AltaGas' results of operations or credit ratings. The increased indebtedness will also make AltaGas' results more sensitive to increases in interest rates.

Availability of Alternative Sources of Funding

It is currently contemplated that a portion of the Bridge Facility will be further reduced or repaid from the cash proceeds of asset sales and the net proceeds of future senior debt, hybrid security, equity or equity-linked security (including any Preferred Shares or convertible debentures) financings completed for the purpose of funding the WGL Acquisition.

There can be no assurance that AltaGas may be able to effect any of these actions on satisfactory terms, or at all. The inability to access such alternate sources of funding to reduce or repay the Bridge Facility may negatively impact the financial performance of AltaGas, including the extent to which the WGL Acquisition is accretive.

The availability to AltaGas of borrowings under the Bridge Facility is subject to various conditions

AltaGas' ability to borrow under the Bridge Facility is subject to certain customary conditions that AltaGas must satisfy. If AltaGas is unable to satisfy one or more of those conditions and such conditions are not waived, AltaGas will not be able to borrow amounts under the Bridge Facility to fund the WGL Acquisition. If AltaGas cannot borrow under the Bridge Facility, a financing failure under the Merger Agreement will have occurred and, if AltaGas does not otherwise have the cash to close the WGL Acquisition, WGL will, in certain circumstances, have the right to terminate the Merger Agreement and receive a termination fee. In addition, while it is possible that alternative sources of financing may not be available, alternative sources, if available, may be on terms that are less favourable than the terms of the Bridge Facility.

Dividends and Dividend Equivalent Payments

The declaration and payment of dividends on Common Shares and accordingly, the Dividend Equivalent Payment, by AltaGas are at the discretion of the board of directors of AltaGas. The cash available for dividends 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. Following closing of the WGL Acquisition, AltaGas' ability to pay dividends could be adversely affected if the free cash flow resulting from the WGL Acquisition does not materialize as expected when coupled with the potentially dilutive effect of the additional Common Shares issued in exchange for the Subscription Receipts issued in the Offering and the Concurrent Private Placement. In addition, AltaGas' ability to pay dividends depends upon the payment of dividends by certain of AltaGas' subsidiaries or the repayment of funds to AltaGas by its subsidiaries. AltaGas' subsidiaries, including WGL following the WGL Acquisition, in turn, may be restricted from paying dividends, making repayments or making other distributions to AltaGas for financial, regulatory, legal or other reasons. To the extent AltaGas' subsidiaries are not able to pay dividends or repay funds to AltaGas, it may adversely affect AltaGas' ability to pay dividends on Common Shares and accordingly, the Dividend Equivalent Payment.

RISKS RELATED TO THE BUSINESS OF WGL

The risk factors set forth in this AIF relating to the business and operations of AltaGas that are similar to WGL's business, including AltaGas' utility and natural gas distribution business apply equally in respect of similar components of WGL's business. In addition, certain incremental risks to AltaGas following closing of the WGL Acquisition in relation to WGL's business are set forth below.

Silver Spring, Maryland Incident

Washington Gas continues to support the investigation by the National Transport Safety Board (NTSB) into the August 10, 2016 explosion and fire at an apartment complex in Arliss Street in Silver Spring, Maryland, the cause of which has not been determined. On November 2, 2016 two civil actions were filed in the District of Columbia Superior Court by residents of the apartment complex. In one lawsuit, twenty nine plaintiffs seek unspecified damages for wrongful death and personal injuries. In the other lawsuit, an additional seven plaintiffs seek class action status on behalf of all residents and guests of residents who suffered damages for loss of personal property and lost wages seeking total damages described as not exceeding $5 million. Eighteen civil actions have been filed in the Circuit Court for Montgomery, County, Maryland seeking unspecified damages for personal injury and property damage. While Washington Gas maintains excess liability insurance coverage from highly-rated insurers, subject to a nominal self-insured retention, at this time the cause of the incident has not been determined and management of Washington Gas is unable to determine a range of potential losses that are reasonably possible of occurring. Washington Gas was invited by the NTSB to be a party to the investigation and in that capacity continues to work closely with the NTSB to help determine the cause of this incident.

WGL's ability to meet its customers' requirements may be impaired if contracted supply is not available, if supplies are not delivered in a timely manner, if WGL loses key suppliers or if WGL is not able to obtain additional supplies during significant spikes in demand

Washington Gas must acquire adequate natural gas supply and pipeline and storage capacity to meet current and future customers' annual and seasonal natural gas requirements. Similarly, WGL Energy Services requires adequate natural gas and electric supplies to serve the demands of its customers and WGL Midstream requires adequate natural gas supply and storage and pipeline capacity to meet its delivery obligations to its customers. WGL depends on the ability of natural gas producers, pipeline gatherers, natural gas processors, interstate pipelines, suppliers of electricity and regional electric transmission operators to meet these requirements. If WGL is unable to secure adequate supplies in a timely manner because of a failure of its suppliers to deliver the contracted commodity, capacity or storage, if WGL is unable to secure additional quantities during significant abnormal weather conditions, or if Washington Gas' or WGL Energy Services' interruptible customers fail to comply with requests to curtail their gas usage during periods of sustained cold weather, WGL may be unable to meet its customers' requirements. Such inability could result in defaults under contracts with customers, penalties and financial damage payments, costs relating to procedures to recover from a disruption of service, the loss of key licenses and operating authorities, and the loss of customers, which could have a material adverse effect on WGL's financial results.

Rules implementing the derivatives transaction provisions of the Dodd-Frank Act could have an adverse impact on WGL's ability to hedge risks associated with its business

The Dodd-Frank Act regulates derivatives transactions, which include certain instruments, such as interest rate swaps, and commodity option, financial and other contracts, used in WGL's risk management activities. The Dodd-Frank Act requires that most swaps be cleared through a registered clearing facility and that they be traded on a designated exchange or swap execution facility, with certain exceptions for entities that use swaps to hedge or mitigate commercial risk. The Dodd-Frank requirements relating to derivative transactions have not been fully implemented by the U.S. Securities and Exchange Commission and the Commodity Futures Trading Commission. When fully implemented, the law and any new regulations could increase the operational and transactional cost of derivatives contracts and affect the number and/or creditworthiness of available counterparties. In addition, WGL may transact with counterparties based in other jurisdictions which, like the U.S., are in the process of implementing regulations to regulate derivatives transactions, some of which are currently in effect and may impose costs on WGL's derivatives activities.

The availability of adequate interstate pipeline transportation capacity and natural gas supply may decrease

WGL purchases almost all of its natural gas supply from interstate sources that must then be transported to WGL's service territory. In particular, while the Marcellus Shale region is rapidly developing as a premier gas formation, the interstate pipeline transportation capacity may limit the availability of gas from Marcellus in the near term. A significant disruption to or reduction in interstate pipeline capacity due to events such as operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist or cyber-attacks or other acts of war, or legislative or regulatory actions or requirements, including remediation related to integrity inspections, could reduce WGL's normal interstate supply of gas, which may affect its ability to serve customer demand and may reduce its earnings. Additionally, WGL may face increased supply risk due to the weakened market conditions experienced by exploration and production companies.

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the performance of investments, demographics, and other factors and assumptions. These changes may have a material adverse effect on WGL

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the market value of WGL's retirement plan assets, changing bond yields, changing demographics and changing assumptions. Any sustained declines in equity markets, reductions in bond yields, increases in health care cost trends, or increases in life expectancy of beneficiaries may have an adverse effect on WGL's retirement plan liabilities, assets and benefit costs. Additionally, WGL may be required to increase its contributions in future periods in order to preserve the current level of benefits under the plans and/or due to U.S. federal funding requirements.

The construction of WGL Midstream's pipeline assets have experienced and may continue to experience legislative and regulatory obstacles, and the construction and operation of these assets are subject to hazards, equipment failures, supply chain disruptions, personnel issues and related risks, which could result in decreased values of these investments, including impairments, and/or delays their in-service dates, which would negatively affect WGL's results of operations

WGL Midstream's business plan involves making substantial investments in pipeline construction projects, which are subject to FERC and state agency regulation and approval. These construction projects are also subject to environmental, political and legal uncertainties that are beyond WGL's control. In April 2016, the New York State Department of Energy and Conservation declined to grant a Water Quality Certification required in connection with the construction of one of these investments, the Constitution Pipeline. WGL's investee, Constitution Pipeline Company, LLC, is pursuing litigation to overturn this ruling. If this litigation is unsuccessful, and/or if other agencies deny or delay approval for this project or other midstream projects, or enact additional legislation or regulations related to these activities, the value of these investments may decrease and could be impaired. In addition, these developments may reduce some opportunities to grow WGL's midstream business. In addition, the construction and operation of WGL Midstream's pipeline assets are subject to risks relating to breakdowns or failures of equipment or processes due to pipeline integrity, fuel supply or transportation disruptions, accidents, labor disputes or work stoppages, construction delays or cost overruns, and shortages of or delays in obtaining equipment, material and labor. Because these assets are interconnected with facilities of third parties, the operation of these facilities could also be adversely affected by unexpected or uncontrollable events occurring on the systems of such third parties. These events could further delay the in-service date of WGL Midstream's projects or disrupt operations on these projects, which could have an adverse effect on its financial results.

Returns on WGL's non-utility subsidiaries' investments in renewable energy projects are dependent upon regulatory and tax incentives, which may expire or be reduced or modified

WGL Energy Systems derives a significant portion of its revenues from the sale of solar RECs, which are produced as a result of owning and operating commercial distributed energy systems. The value of these solar RECs is determined by markets in the states where the distributed energy systems are installed, which are driven by state laws relating to renewable portfolio standards or alternative compliance payment requirements for renewable energy. Overbuilding of distributed energy systems in these states or legislative changes reducing renewable portfolio standards or alternative compliance payment requirements could negatively impact the price of solar RECs that WGL sells and the value of the solar RECs that WGL holds in its portfolio. In addition, WGL Energy Systems and WGSW's investment strategy to own and operate energy assets and sell energy to customers is based on the investment tax credit provision in the U.S. federal tax code, which historically has allowed WGL to reduce its tax burden by investing in renewable and alternative energy assets, such as distributed energy, ductless heat pumps and fuel cells. WGL's ability to benefit from the investment tax credit is based on certain assumptions about the level of WGL's income taxes. Congress extended the investment tax credit for renewable energy projects in December, 2015 through 2021, while it also extended bonus depreciation provisions for all energy and utility capital assets through 2019. The extension of the bonus depreciation provision may reduce WGL's ability to monetize investment tax credits on a timely basis, thus diminishing WGL Energy Systems' competitiveness in securing future assets to continue its growth.

Failure of WGL's service providers, including in connection with the transition of certain outsourcing relationships to new vendors, could negatively impact WGL's business, results of operations and financial condition

Certain of WGL's information technology, customer service, supply chain, pipeline and infrastructure installation and maintenance, engineering, payroll and human resources functions that WGL relies on are provided by third party vendors. Some of these services may be provided by vendors from centers located outside of the United States. Services provided pursuant to these agreements could be disrupted due to events and circumstances beyond WGL's control. Furthermore, WGL is in the process of transferring some of these services to new vendors. The transition of service providers could lead to a loss of institutional knowledge, service disruptions and decreased customer satisfaction. WGL's reliance on these service providers could have an adverse effect on WGL's business, results of operations and financial condition.

Competition may negatively affect WGL's non-utility subsidiaries

WGL faces strong competition in its non-utility segments. WGL Energy Services competes with other non-regulated retail suppliers of natural gas and electricity, as well as with the commodity rate offerings of electric and gas utilities. Increases in competition, including utility commodity rate offers that are below prevailing market rates, may result in a loss of sales volumes or a reduction in growth opportunities. WGL Midstream competes with other midstream infrastructure and energy services companies, wholesale energy suppliers and other non-utility affiliates of regulated utilities to acquire natural gas storage and transportation assets. WGL Energy Systems faces many competitors in the commercial energy systems segment, including, for government customers, companies that contract with customers under Energy Savings Performance Contracting (ESPC) and other utilities providing services under Utility Energy Saving Contracts (UESC) and, in the renewable energy and distributed generation market, other developers, tax equity investors, distributed generation asset owner firms and lending institutions. These competitors may have diversified energy platforms with multiple marketing approaches, broader geographic coverage, greater access to credit and other financial resources, or lower cost structures, and may make strategic acquisitions or establish alliances among themselves. There can be no assurances that WGL can compete successfully, and its failure to do so could have an adverse impact on WGL's results of operations and cash flow.

Delays in U.S. federal government budget appropriations may negatively impact WGL Energy Systems' earnings

The Energy Efficiency and Energy Management operations of WGL Energy Systems are sensitive to U.S. federal government agencies' receipt of funding in a timely manner. A significant portion of WGL Energy Systems revenues is derived from implementing projects related to energy efficiency and energy conservation measures for federal government agencies in the Washington D.C. metropolitan area. A delay in funding for these federal agencies directly impacts completion of ongoing projects and may harm WGL Energy Systems' ability to obtain new contracts, which may negatively impact earnings.

ENVIRONMENTAL AND SAFETY POLICIES AND SOCIAL RESPONSIBILITY

AltaGas operates in a safe, reliable manner and maintains positive relationships with its stakeholders in the communities in which it operates including with Aboriginal groups and regulators. AltaGas has three guiding principles for developing energy infrastructure: respect the land, share the benefits, and nurture long-term relationships.

Safety and environmental stewardship are core values at AltaGas and integral to how AltaGas conducts its operations. The safety of AltaGas' employees, contractors, and others impacted by AltaGas' operations in addition to protecting the environment and minimizing AltaGas' impact on the environment are critical to AltaGas maintaining a sustainable business. In support of this commitment, AltaGas holds its employees and others working or performing services on AltaGas' behalf to the same expectations of environmental protection, accountability and stewardship.

To help ensure the responsibility and accountability for environmental protection, AltaGas maintains an integrated management system, which provides a framework for how AltaGas operates. AltaGas educates its employees on environmental safeguarding and safety. AltaGas operates its businesses in compliance with regulatory requirements and good industry practices and regularly monitors environmental performance and safety systems and processes. AltaGas also maintains and practices emergency preparedness systems and procedures.

In addition, the Board of Directors has established the EOH&S Committee, which monitors and makes recommendations to the board of directors with respect to the environment, health and safety policies, practices and procedures of AltaGas and its affiliates and through regular reports monitors the operation of the environmental risk management system established by this committee.

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 various substances discharged to the air, land, and water in association with certain oil and natural gas and power industry operations, as well as restrictions on use of land and water in association with certain operations. AltaGas' operations are required to obtain and comply with a variety of environmental licenses, permits, approvals, and registrations. In addition to the license and permit requirements, provincial, state, territorial and federal legislation may require that end of life assets be abandoned, remediated, and reclaimed to the satisfaction of provincial, state or territorial authorities. Failure to comply with applicable environmental legislation can result in civil or criminal penalties, environmental contamination clean-up requirements, and government orders affecting future operations. 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 risk on an ongoing basis and strategically manages its liabilities portfolio to meet jurisdictional requirements while reducing risk exposure.

AltaGas may be subject to opposition from special interest groups resulting in regulatory process delays, which can impact schedules and increase cost. Please refer to the "Risk Factors" section of this AIF and in particular the risk factor on "External Stakeholder Relations".

CLIMATE CHANGE

Changes in laws and regulations relating to GHG emissions could require AltaGas, in addition to complying with GHG monitoring and reporting requirements applicable to its operations, to (i) comply with stricter emissions standards for internal combustion engines; (ii) take additional steps to control transmission and distribution system leaks; (iii) retrofit existing AltaGas equipment with pollution controls or replace such equipment; and/or (iv) reduce AltaGas' GHG emissions or, depending on the requirements enacted, acquire emissions offsets, credits or allowances or pay taxes on the GHG emitted in connection with its operations. AltaGas' business could also be indirectly impacted by GHG 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.

International Climate Change Agreements

As a signatory to the United Nations Framework Convention on Climate Change (the UNFCCC) and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17 percent reduction in GHG emissions from 2005 levels by 2020. In May 2015, Canada submitted its Intended Nationally Determined Contribution (INDC) to the UNFCCC, ahead of the 2015 United Nations Climate Change Conference, held in Paris (COP 21). As a result, the Government of Canada will replace the 17 percent reduction target established in the Copenhagen Agreement with its INDC of 30 percent reduction below 2005 levels by 2030. INDCs were communicated prior to the COP 21 and constitute the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The UNFCCC adopted the Paris Agreement on December 12, 2015 and both Canada and the U.S.

are signatories. The Paris Agreement came into force on November 4, 2016, however it is not clear whether the U.S. will remain a signatory after the election of President Trump who has previously communicated his intention to withdraw.

To meet part of its commitments to the Paris Agreement, Canada will impose a tax on carbon emission starting in 2018. See "Pan-Canadian Climate Change Plan" below. The full impact of the Canadian Government's commitment to the Paris Agreement is not yet clear.

Canadian Federal Air and GHG Regulations

Multi-Sector Air Pollutants Regulations

The Multi-Sector Air Pollutants Regulations, promulgated under the Canadian Environmental Protection Act, 1999 (the Canadian EPA), was passed on June 17, 2016. The regulation requires owners and operators of specific industrial facilities and equipment types to meet consistent performance standards across the country. The objectives of the regulations are to:

- Limit the amount of nitrogen oxides (NOx) emitted from modern (new) and pre-existing (existing), gaseous-fuel-fired non-utility boilers and heaters used in many industrial facilities;
- Limit the amount of NOx emitted from modern and pre-existing stationary spark-ignition gaseous-fuel-fired engines used by many industrial facilities (e.g., those used for gas compression or back-up generators); and
- Limit the amount of NOx and sulphur dioxide (SO_2) emitted from cement kilns.

Certain provisions of the regulations will come into effect on July 1, 2017, requiring registration and compliance reporting for modern engines. Compliance obligations for pre-existing engines will be introduced in 2019 that will include NOx limits, NOx testing and oxygen (O_2) measurements, specified maintenance/operational requirements, and annual reporting and record keeping. Regulated entities will be subject to enforcement and compliance requirements and penalties as specified under the Canadian EPA. AltaGas is currently assessing the impact of the regulation on its operations as it relates to compliance obligations, maintenance requirements, reporting and retrofitting of existing engines.

Pan-Canadian Climate Change Plan

In addition, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022.

Canada's four biggest provinces, Ontario, Quebec, Alberta and British Columbia, have already adopted carbon pricing plans, but the current price limit in each of those provinces is well below the minimum $50 per tonne level required in 2022 as proposed by the federal government. The impact of a federal carbon pricing structure is expected to be varied across AltaGas business segments as the pricing structure catches up with provincial carbon pricing models that are already in place. The immediate (five year) carbon tax impact on AltaGas will mainly impact AltaGas' gas and power segments, while AltaGas' utilities are expected to pass-through the carbon tax to their customers.

Federal Greenhouse Gas Reporting Programme (GHGRP)

Currently, AltaGas is required to report carbon dioxide equivalent emissions (CO_2e) emissions under the *Canadian Environmental Protection Act* for all facilities which emit 50,000 tonnes or more of CO_2e. As a result, AltaGas currently files emission reports with the federal government for its Gordondale, Harmattan, and Blair Creek facilities.

Environment and Climate Change Canada is proposing to reduce the reporting threshold for the GHGRP starting with the 2017 reporting year. Under this rule change, the threshold would be reduced from 50,000 tonnes CO_2e to 10,000 tonnes CO_2e. Further, from 2018, the GHGRP will require additional data to align federal reporting requirements with provincial GHG reporting requirements.

The number of AltaGas facilities reporting to the GHGRP is expected to increase from three up to twelve with the introduction of the proposed lower threshold of 10,000 tonnes CO_2e, resulting in a significant increase in regulatory reporting obligations.

Canadian Provincial GHG Regulations

Alberta

Specified Gas Emitters Regulation (SGER)

SGER under the *Climate Change and Emissions Management Act* (Alberta) took effect on July 1, 2007 and was amended in June of 2015. The regulation applies to large emitter facilities with direct emissions totalling 100,000 tonnes or more of carbon dioxide equivalent per annum, requiring a large emitter in its ninth or subsequent year of commercial operation to achieve a net emission intensity of 85 percent in 2016 and 80 percent in 2017 relative to the baseline emissions intensity that was established for the facility. Newer facilities are required to phase in annual emissions intensity reduction targets commencing in its 4^{th} year of commercial operation.

Compliance options include: (i) making facility enhancements to reduce GHG 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 to reduce GHG emissions in the province. The amount of money that a facility owner must contribute to the Climate Change and Emissions Management Fund to obtain one fund credit equal to a one tonne reduction in emissions was set at $20 in 2016, increasing to $30 in 2017.

Both Harmattan and Gordondale are considered large emitters under Alberta's *Specified Gas Emitters Regulation*.

In 2016, AltaGas' Turin and Bantry acid gas injection facilities reduced direct GHG emissions, by approximately 120,000 tonnes of CO_2e, through the geological sequestration of CO_2 and hydrogen sulfide.

Climate Leadership Act

On June 13, 2016, the Climate Leadership Act was enacted introducing an initial economy-wide levy of $20 per tonne effective January 1, 2017, and increasing to $30 per tonne in January of 2018. All fuel consumption, including gasoline and natural gas, will be subject to the levy, with certain exemptions. The SGER regime will continue to govern until the end of 2017 for large emitters. As of January 1, 2018, the Government of Alberta has announced that it intends to transition to a proposed Carbon Competitiveness Regulation, in which sector specific output-based carbon allocations will be used to ensure competitiveness.

Renewable Electricity Act

On December 14, 2016, the Renewable Electricity Act was enacted pursuant to which the Government of Alberta will provide funding support to new renewable electricity projects to replace two thirds of currently produced coal-fired power in the province (all of which will be retired by 2030). The Renewable Electricity Act establishes a target of 30 percent renewable electricity by 2030 and the Government of Alberta has publicly announced a commitment to at least 5,000 MW. The remaining third of coal-fired power is to be replaced by new or converted natural-gas fired power plants. To ensure the development of the necessary gas-fired power production to displace coal, the Government announced on November 23, 2016 that Alberta's energy-only electricity market will be restructured and a capacity market will be in place with initial procurements undertaken by 2021.

British Columbia (B.C.)

Greenhouse Gas Industrial Reporting and Control Act

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act came into force on ensuring LNG facilities in B.C. will have an emissions cap and replaced the previous Greenhouse Gas Reduction (Cap and Trade) Act.

Three regulations necessary to implement the Act are in effect Jan. 1, 2016:

The Greenhouse Gas Emission Reporting Regulation replaces the existing industrial Reporting Regulation and adds compliance reporting requirements, including specific requirements for LNG operations. Industrial operations will continue to report GHG emissions as they have since 2010.

The Greenhouse Gas Emission Administrative Penalties and Appeals Regulation establish the process for when, how much, and under what conditions administrative penalties may be levied for non-compliance with the act or regulations.

The Greenhouse Gas Emission Control Regulation establishes the B.C. Carbon Registry and sets criteria for developing emission offsets issued by the Province. The regulation also establishes the price ($25) for funded units issued under the act that would go towards a technology fund. Regulated operations, such as LNG operations, will purchase offsets from the market or funded units from government to meet emission limits.

AltaGas' Blair Creek, Younger, and Townsend facilities are subject to the reporting obligations imposed by the *Greenhouse Gas Emission Reporting Regulation*.

Carbon Tax Act

Pursuant to the *Carbon Tax Act*, B.C. introduced a carbon tax of $10/tonne in 2008 and increased it to $30/tonne in 2012. In 2013, the tax was frozen at $30 per tonne for five years to allow other jurisdictions time to catch up with comparable carbon pricing mechanisms.

British Columbia Climate Leadership Plan (B.C. Climate Leadership Plan)

The British Columbia Government unveiled the Climate Leadership Plan in August 2016. B.C.'s Climate Leadership Plan identifies key areas where British Columbia can take action now to reduce greenhouse gas emissions. Highlights from the plan below:

1. Launching a strategy to reduce methane emissions:
    - Targeting extraction and processing emissions (referred to as upstream in the natural gas sector), targeting a 45 percent reduction by 2025 in fugitive and vented emissions in infrastructure built before January 1, 2015.
2. Regulating carbon capture and storage projects:
    - Carbon capture and storage projects will be able to proceed upon the completion of regulatory policy work.
3. Making B.C.'s electricity 100 percent renewable or clean:
    - 100 percent of the electricity acquired by BC Hydro on the integrated grid must now be from renewable or clean sources, except where concerns regarding reliability or costs must be addressed, with allowance for natural gas generation for reliability.
4. Expanding incentives to promote adoption of efficient gas equipment:
    - Expand incentives by at least 100 percent, to encourage further adoption of technologies that reduce the emissions from gas fired equipment and facilitating projects that will help fuel marine vessels and commercial vehicles with cleaner burning natural gas.

Details regarding how the plan will be implemented have not been released but AltaGas is actively monitoring the developments of the plan to assess how it will impact AltaGas' business.

U.S. Federal Air and GHG Regulations

Clean Air Act

Under the Clean Air Act, the United States Environmental Protection Agency (EPA) has the authority to set federal ambient air quality standards for certain air pollutants which apply throughout the U.S. and to issue operating permits to, among other things, authorize and monitor emissions. Individual states must ensure that at minimum their air quality meets the federal standards set by the EPA.

All of AltaGas' operating natural gas-fired power generation facilities located in the U.S. operate under and comply with requirements set forth in the operating permits issued to such facility.

Clean Power Plan

On February 9, 2016, the U.S. Supreme Court stayed implementation of the final rule of the Clean Power Plan previously announced by President Obama and the EPA in August of 2015, pending judicial review. The Clean Power Plan requires each state to create its own plan to lower carbon emissions by 32 percent from 2005 levels by 2030. Under the final rule, each state will have until 2018 to submit its plan and must begin reducing emissions by 2022.

Greenhouse Gas Reporting Program (GHGRP)

The GHGRP (codified at 40 CFR Part 98) requires reporting of greenhouse gas (GHG) data and other relevant information from large GHG emission sources, fuel and industrial gas suppliers, and CO_2 injection sites in the United States. A total of 41 categories of reporters are covered by the GHGRP. Facilities determine whether they are required to report based on the types of industrial operations located at the facility, their emission levels, or other factors. Facilities are generally required to submit annual reports under Part 98 if:

- GHG emissions from covered sources exceed 25,000 metric tons CO_2e per year.
- Supply of certain products would result in over 25,000 metric tons CO_2e of GHG emissions if those products were released, combusted, or oxidized.
- The facility receives 25,000 metric tons or more of CO_2 for underground injection.

All of AltaGas' operating facilities located in the U.S. operate under and comply with requirements set forth by the Greenhouse Gas Reporting Program.

California GHG Regulations

AB 32

Assembly Bill No. 32 (AB 32), the California Global Warming Solutions Act of 2006, requires California to reduce its GHG emissions to 1990 levels by 2020, a reduction of approximately 15 percent below emissions expected under a business as usual scenario. In April of 2015, California Air Resources Board announced it would be moving forward with greenhouse gas reduction targets of 40 percent below 1990 levels by 2030.

SB 32

Senate Bill No. 32 (SB 32), enacted in September 2016 and effective January 1, 2017, sets California's greenhouse gas reduction target to 40 percent below 1990 levels by 2030.

Senate Bill X1-2

In April 2011, Governor Edmund G. Brown, Jr., signed Senate Bill X1-2, revising the Renewable Energy Resources Program to effectively increase the amount of electricity generated from eligible renewable energy resources to at least 33 percent of retail sales of electricity in California per year by December 31, 2020.

Senate Bill No. 350 (SB 350)

SB 350, the Clean Energy and Pollution Reduction Act of 2015 requires that the amount of electricity generated and sold to retail customers per year from eligible renewable energy resources be increased to 50 percent by December 31, 2030. The bill also provides for a potential expansion of CAISO into a regional organization to promote the development of regional electricity transmission markets in the western states, but does not mandate that transition. AltaGas expects this will increase demand for highly-responsive generation and energy storage assets such as the Pomona Energy Storage Facility and AltaGas believes that it is well positioned to take advantage of this opportunity with its existing natural gas-fired assets in California.

Cap-and-Trade Program

The California Air Resources Board (ARB) designed the California cap-and-trade program to meet the requirements of AB 32. The cap-and-trade is a market based regulation designed to reduce GHG emissions from multiple sources by setting a cap on GHG emissions. The program began in 2013 with a cap that declines at approximately 3 percent per annum.

As of December 31, 2016, all of AltaGas' operating natural gas-fired power generation facilities in California were in compliance with their air permit requirements, which are issued in accordance with federal and state emissions standards and costs associated with meeting AB 32 and California's cap-and-trade program were passed through to the utilities pursuant to the applicable PPA.

California Groundwater Regulation

In California, water supply availability can be volatile, particularly as implementation moves forward with the relatively recent enactment of the Sustainable Groundwater Management Act (SGMA). SGMA is entirely new and a mandatory set of laws and regulations aimed toward managing groundwater so that the groundwater is "sustainable" over the long term. SGMA is designed to defer to local public agencies for regulating the groundwater. Local agencies are expected to collect data from groundwater users, such as groundwater use, as well as levy fees or assessments for administration and enforcement costs related to implementing SGMA. These local public agencies, referred to as Groundwater Sustainability Agencies, are charged with ensuring groundwater levels rise so that the aquifers can be used for decades to come without contributing to land subsidence or other "undesirable results" as described in SGMA. Although SGMA is focused on groundwater supplies, reduced availability of groundwater might increase surface water demands, whether originating from local or imported surface water supply sources. In these early stages of implementation, it is uncertain whether or how SGMA may impact water supplies for AltaGas' power generation facilities in California. See "Risk Factors" and in particular the risk factor on "Sufficiency of Water Supply Reliability for the California Assets".

Decommissioning, Abandonment and Reclamation Costs

AltaGas is responsible for compliance with all applicable laws and regulations regarding the decommissioning, abandonment and reclamation of its facilities at the end of their economic life, the costs of which may be substantial. It is not possible to predict these costs with certainty since they are a function of regulatory requirements at the time of decommissioning, abandonment and reclamation and the actual costs may exceed current estimates which are the basis of the asset retirement obligation shown in AltaGas' financial statements.

AltaGas engages reputable third party consultants and experienced employees to collect, review and assess relevant data to support the estimates of AltaGas' asset retirement obligations. AltaGas performs end-of-life reviews for its key assets and completes site specific liability assessments in accordance with jurisdictional requirements.

DIVIDENDS

Dividends are declared 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 currently 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. Holders of Subscription Receipts are entitled to receive

Dividend Equivalent Payments, see "Capital Structure" section of this AIF for details. Dividends on the Series A Shares, Series B Shares, Series C Shares, Series E Shares, Series G Shares and Series I Shares are paid quarterly.

AltaGas' payment of dividends may be limited by covenants under its credit agreements including in circumstance when a default or event of default exists or would be reasonably expected to exist upon or as a result of making such dividend payment. 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 below shows the cash dividends paid by AltaGas on Common Shares and Preferred Shares for the three most recently completed financial years.

$ per share	2016	2015	2014
Common Shares	2.020000	1.867500	1.670000
Series A Shares	0.845000	1.148750	1.250000
Series B Shares	0.786920	0.191560	-
Series C Shares(1)	1.100000	1.100000	1.100000
Series E Shares	1.250000	1.250000	1.307400
Series G Shares	1.187500	1.187500	0.586500
Series I Shares	1.448245	-	-

Note:
(1) Amounts disclosed are in U.S. dollars.

PREMIUM DIVIDEND™, DIVIDEND REINVESTMENT AND OPTIONAL CASH PURCHASE PLAN

Effective May 17, 2016, AltaGas replaced in its entirety, its dividend reinvestment plan with the Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (the Plan). The Plan consists of three components: a Premium Dividend™ component, a Dividend Reinvestment component and an Optional Cash Payment component.

The Plan provides eligible holders of Common Shares with the opportunity to, at their election, either: (1) reinvest the cash dividends paid by AltaGas on their Common Shares towards the purchase of new Common Shares at a 3 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); or (2) reinvest the cash dividends paid by AltaGas on their Common Shares towards the purchase of new Common Shares at a 3 percent discount to the average market price (as defined below) on the applicable dividend payment date and have these additional Common Shares of AltaGas exchanged for a cash payment equal to 101 percent of the reinvested amount (the Premium Dividend™ component of the Plan).

In addition, the Plan 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 Toronto Stock Exchange 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 Premium Dividend™ component of the Plan. Shareholders resident outside of Canada (other than the U.S.) may participate in the Dividend Reinvestment component or the Optional Cash Payment Component of the Plan only if their participation is permitted by the laws of the jurisdiction in which they reside and provided that AltaGas is satisfied in its sole discretion, that such laws do not subject the Plan or AltaGas to additional legal or regulatory requirements.

™ Denotes trademark of Canaccord Genuity Corp.

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 2016 as reported by the TSX:

Month	High	Low	Volume Traded
January	32.80	27.25	9,551,670
February	33.98	29.57	7,169,232
March	33.80	31.98	5,522,764
April	33.36	29.87	7,118,909
May	31.54	28.86	9,483,198
June	31.83	30.01	13,698,991
July	33.40	30.55	8,755,168
August	34.95	32.56	7,838,219
September	34.93	32.70	6,381,710
October	35.55	32.79	7,042,658
November	33.47	31.12	7,082,045
December	34.50	32.13	5,738,969

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 2016 as reported by the TSX:

Month	High	Low	Volume Traded
January	16.44	13.80	99,690
February	14.95	13.28	84,405
March	15.12	13.70	141,299
April	16.00	14.91	98,864
May	16.94	15.10	84,783
June	16.85	15.33	187,976
July	16.58	15.37	188,421
August	16.83	16.20	156,309
September	16.90	16.00	199,647
October	17.29	15.91	112,881
November	17.21	16.37	150,270
December	18.23	16.82	443,005

Series B Shares are traded on the TSX under the symbol ALA.PR.B. The following table sets forth the monthly price range and volume traded for Series B Shares for the period from January to December 2016 as reported by the TSX:

Month	High	Low	Volume Traded
January	14.15	12.65	29,537
February	13.74	12.50	24,611
March	14.26	12.50	13,714
April	15.00	14.00	20,730
May	16.00	13.96	46,780
June	15.90	14.25	62,191
July	15.65	14.51	18,576
August	16.00	15.14	24,290
September	15.90	14.99	38,336
October	15.90	14.72	43,825
November	16.23	15.15	88,063
December	17.11	15.90	48,242

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 2016 as reported by the TSX:

Month	High	Low	Volume Traded
January	20.30	16.46	110,354
February	17.99	16.48	106,315
March	18.95	17.19	97,141
April	19.90	18.40	74,487
May	20.30	19.30	100,594
June	20.20	19.12	102,723
July	19.20	18.30	150,849
August	20.76	18.90	178,916
September	20.90	19.75	86,633
October	21.76	20.60	105,866
November	22.79	21.25	163,080
December	23.50	22.10	143,735

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 2016 as reported by the TSX:

Month	High	Low	Volume Traded
January	21.54	16.90	134,491
February	17.90	16.24	138,800
March	19.39	16.00	218,318
April	20.25	19.30	154,336
May	20.48	19.15	132,605
June	20.70	17.99	189,378
July	20.33	18.20	136,208
August	21.25	20.01	140,729
September	21.40	20.42	194,223
October	21.98	20.69	244,639
November	22.60	20.46	208,104
December	23.73	22.30	156,901

Series G Shares are traded on the TSX under the symbol ALA.PR.G. The following table sets forth the monthly price range and volume traded for Series G Shares from January to December 2016 as reported by the TSX:

Month	High	Low	Volume Traded
January	21.12	16.51	281,724
February	17.60	15.81	169,547
March	19.20	15.80	83,818
April	19.73	18.99	118,773
May	20.20	18.80	76,614
June	20.20	17.00	199,730
July	19.85	17.78	108,662
August	20.71	19.58	151,895
September	20.80	19.73	155,212
October	21.42	20.02	173,560
November	21.84	20.50	241,579
December	22.46	21.29	255,979

Series I Shares are traded on the TSX under the symbol ALA.PR.I. The following table sets forth the monthly price range and volume traded for Series I Shares for the period of January to December 2016 as reported by the TSX:

Month	High	Low	Volume Traded
January	25.09	22.26	579,526
February	24.17	23.05	199,626
March	25.00	23.89	149,350
April	25.09	24.10	211,525
May	25.09	24.70	138,975
June	25.30	24.78	238,024
July	25.77	25.08	224,373
August	25.74	25.50	72,919
September	25.75	25.40	136,952
October	25.93	25.40	83,862
November	25.99	25.25	128,130
December	25.87	25.49	110,304

The Subscription Receipts commenced trading on the TSX under the symbol ALA.R, on February 3, 2017 and Series K Shares commenced trading on the TSX under the symbol ALA.PR.K on February 22, 2017.

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.

On December 16, 2015, S&P revised AltaGas' issuer rating and senior unsecured MTN rating to BBB with a Negative Outlook. On January 16, 2017, S&P reaffirmed the BBB with a Negative Outlook. On November 19, 2016, DBRS affirmed the BBB rating with a stable trend for AltaGas. On January 26, 2017, DBRS revised the rating to BBB Under Review with Developing Implications.

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. On January 26, 2017, DBRS revised the outlook to Under Review with Developing Implications.

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.

The ratings action "Under Review" is applied, among other things, when a significant event occurs that directly impacts the credit quality of a particular entity or group of entities and there is uncertainty regarding the outcome of the event such that DBRS is unable to provide an objective, forward-looking opinion in a timely fashion. A rating that is "Under Review" remains outstanding; however, this status acts as a warning signal indicating that the outstanding rating may no longer be appropriate. When a rating is placed "Under Review", DBRS will generally provide initial guidance as to the opinion of DBRS by noting whether the Under Review action has positive (Under Review – Positive), negative (Under Review – Negative) or developing implications (Under Review – Developing). These qualifications indicate the preliminary evaluation of DBRS of the impact on the credit quality of the security or issuer; however as situations and potential rating implications may vary, its final rating conclusion may depart from the preliminary assessment. DBRS will further review the Corporation’s ratings as more information becomes available and aims to resolve the Under Review status of the ratings once financing details are known and the WGL Acquisition has closed.

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. AltaGas has paid each of S&P and DBRS their respective fees in connection with the provision of the above ratings. Over the past two years, in addition to the aforementioned fees, AltaGas has made payments in respect of certain other services provided to the Corporation by S&P.

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, as amended by the first amending agreement dated December 17, 2014 the second amending agreement dated December 4, 2015 and the third amending agreement dated December 8, 2016. This is an unsecured extendible revolving credit facility with Royal Bank of Canada, The Toronto-Dominion Bank, Bank of Montreal, Canadian Imperial Bank of Commerce, The Bank of Nova Scotia, National Bank of Canada, HSBC Bank Canada, Alberta Treasury Branches, Bank of America, N.A., Canada Branch and JP Morgan Chase Bank, N.A., Export Development Canada and their respective affiliates maturing on December 15, 2020. Borrowings on the facility can be by way of prime loans, U.S. base rate loans, LIBOR loans, bankers' acceptances or letters of credit. Borrowings on the facility bear fees and interest at rates relevant to the nature of the draw made;
- The Trust Indenture between AltaGas and Computershare Trust Company of Canada dated July 1, 2010, as supplemented, related to the issuance and sale of MTNs pursuant to AltaGas' medium term note program; and
- The Merger Agreement.

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 during AltaGas' most recently completed financial year and AltaGas is not aware of any such material legal proceedings being contemplated.

REGULATORY ACTIONS

AltaGas is not aware of any (i) penalties or sanctions imposed against it by a court relating to securities legislation or by a securities regulatory authority during its most recently completed financial year, or (ii) other penalties or sanctions imposed by a court or regulatory body against it that would likely be considered important to a reasonable investor in making an investment decision. There were no settlement agreements entered into by AltaGas before a court relating to securities legislation or with a securities regulatory authority during AltaGas' most recently completed financial year.

INTERESTS OF EXPERTS

The auditors of the Corporation are Ernst & Young LLP, Chartered Accountants, 2200 – 215 2nd Street SW, Calgary, Alberta T2P 1M4. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' 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 for AltaGas' most recent annual meeting of Shareholders that involved the election of directors.

Additional financial information is contained in AltaGas' audited consolidated financial statements as at and for the year ended December 31, 2016 and management's discussion and analysis for the year ended December 31, 2016.

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 AIF.

TRANSFER AGENTS AND REGISTRARS

The registrar and transfer agent for the Common Shares, the Subscription Receipts 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.

SCHEDULE A: AUDIT COMMITTEE MANDATE

I. Constitution

The Board of Directors (the Board) of AltaGas Ltd. (AltaGas or the Corporation) has established an Audit Committee (the Committee). The 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

The Board shall elect from its members not less than three (3) Directors to serve on the Committee (the Members) and shall appoint one such Member as Chair of the Committee. Every Member must be:

- a Director of the Corporation,
- independent, and
- financially literate.

No Member 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 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 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 Committee will hold *in camera* sessions with management, and 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 of the Chair

The Chair is responsible for:

a) convening Committee meetings and designating the times and places of those meetings;

b) working with Management on the development of agendas and related materials for Committee meetings;

c) ensuring Committee meetings are conducted in an efficient, effective and focused manner;

d) providing leadership to the Committee and to assist the Committee in reviewing and monitoring its responsibilities; and

e) reporting to the Board on the decisions and recommendations of the Committee.

V. Duties and Responsibilities of the Committee

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) oversight of external auditors, including:

- appointment, compensation, retention and termination of external auditors, who shall report directly to the Committee, provided that the appointment of the auditor shall be subject to shareholder approval;
- review and approval of the terms of the external auditors' annual engagement letter, including the proposed audit fee;
- pre-approve non-audit work undertaken by the external audit firm;
- determine external auditor independence;
- review and approval of AltaGas' hiring policies re: current and former partners and employees of the external auditor;

b) oversight of audits and financial reporting, including:

- review of the audit plan;
- financial statements, including management's discussion and analysis;
- annual and interim press releases regarding financial results;
- reports to shareholders and others;
- filings to securities regulators;
- public disclosure documents containing audited or unaudited financial information (for example, press releases, prospectuses, annual information form, management information circular);
- review of litigation, claims and contingencies;

c) oversight of financial reporting processes and internal controls, including:

- reviewing the adequacy and effectiveness of the accounting and internal control policies of the Corporation and procedures through inquiry and discussions with the external auditors, management and the internal auditor;
- review at least annually with the internal auditor the Corporation's internal procedures, and the scope and plans for the work of the internal audit group;

d) oversight of finance matters, including:

- review and, as required, approve or recommend for approval to the Board, prospectuses and documents, where practicable, which may be incorporated by reference into a prospectus;

- review the issuance of equity or debt securities by the Corporation;

- review and recommend for approval to the Board the management information circular with respect to matters related to the auditor or affecting the capital of the Corporation;

e) oversight of risk management, including a review of the Corporation's major risks, a review of the method of risk analysis by the Corporation, review of the strategies, policies and practices in place for risk management, a review of the Corporation's cyber risk and data security, and a review of the Corporation's insurance program;

f) policies applicable to the Committee's mandate, including:

   a. Accounting and Auditing Irregularity Reporting Policy; and

   b. commodity risk management and related policies;

g) the following other duties:

   a. review at least annually the staffing and succession planning in the accounting and finance groups;

   b. report to the Board after each Committee meeting, as required during the year, with respect to the Committee's activities and recommendations;

   c. meet separately with senior management, the internal auditors, the external auditors and, as is appropriate, internal and external legal counsel and independent advisors in respect of matters not elsewhere listed concerning any other audit, finance and risk matter.

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.

VI. External Auditor

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

The 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.

VII. Relations with Management

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

   a. meet regularly with Management to discuss areas of concern;

   b. review and asses the quality of the executives involved in financial reporting process; and

   c. ensure Management provides adequate funding to the Committee so that it may independently engage and remunerate the Auditor and any key advisors.

VIII. Committee Timetable

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

AltaGas

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