AltaGas

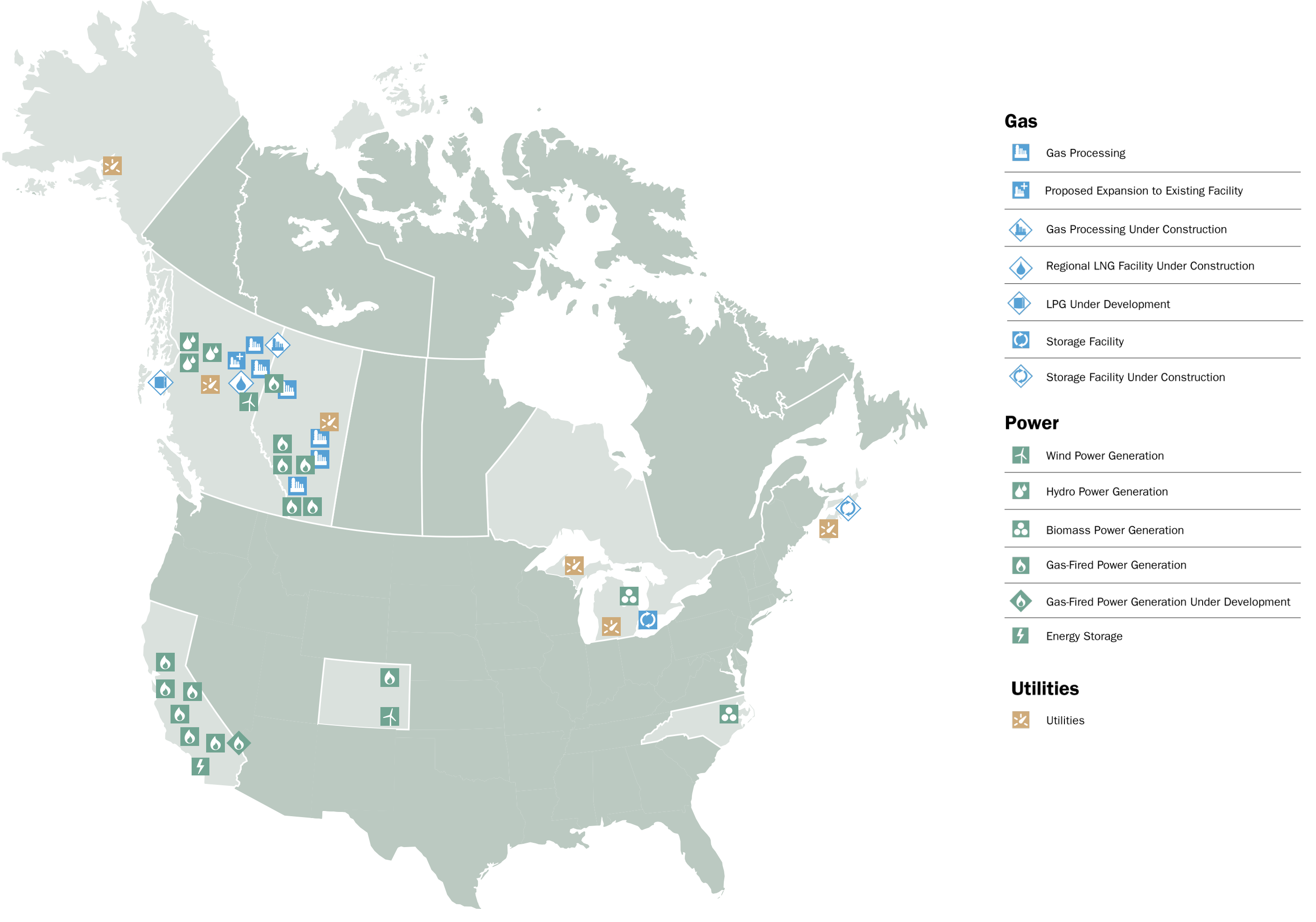
2016 Annual Report

~2 Bcf/d of natural gas transacted

1,688 MW of power generation in four fuel types and 20 MW of energy storage

5 Regulated Gas Distribution franchises serving over 570,000 customers

AltaGas is a leading, North American diversified energy infrastructure company with strong growth opportunities in Gas, Power and Utilities.



AltaGas operates in a safe, reliable manner in close partnership with First Nations and communities. AltaGas has three guiding principles for developing energy infrastructure: Respect the land, share the benefits, and nurture long-term relationships.

Our success has been driven by our employees' commitment to these principles and the support and trust of our shareholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations is provided to enable readers to assess the results of operations, liquidity and capital resources of AltaGas Ltd. (AltaGas or the Corporation) as at and for the year ended December 31, 2016. This MD&A, dated February 22, 2017, should be read in conjunction with the accompanying audited Consolidated Financial Statements and notes thereto of AltaGas as at, and for the year ended, December 31, 2016.

The Consolidated Financial Statements and comparative information have been prepared in accordance with United States (U.S.) generally accepted accounting principles (U.S. GAAP) and in Canadian dollars, unless otherwise indicated.

This MD&A contains forward looking statements. When used in this MD&A the words "may", "can", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "contemplate", "continue", "estimate", "forecast", "expect", "project", "target", "potential" and similar expressions suggesting future events or future performance, as they relate to the Corporation or any affiliate of the Corporation, are intended to identify forward looking statements. In particular, this MD&A contains forward looking statements with respect to, among other things, business objectives, the anticipated benefits of acquisitions and other major projects, the anticipated timing of commercial operations, investment decisions, expenditures and licensing and permitting, expected growth and drivers of growth, capital expenditures (including in respect of the 2017 capital program, expected allocation per business segment and project and anticipated sources of financing thereof), results of operations, operational and financial performance, business projects, opportunities and financial results.

Specifically, such forward looking statements are set forth under the headings: "Overview of the Business", "AltaGas' Vision and Objective", "Strategy", "Strategy Execution", "Recent Developments", "2017 Outlook", "Growth Capital", "Gas", "Power", "Utilities" and "Future Changes in Accounting Principles" and under those headings specifically include 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; the potential for growth through acquisition and development of energy infrastructure and the expectation that such growth in infrastructure will enable AltaGas to establish a western energy hub in northeast British Columbia providing access to export markets off the west coast and access to new markets and higher netbacks to producers in the WCSB; 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 in exposure to commodity market volatility; expectations that expansion of business through acquisitions and organic growth will support dividend and capital growth; 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 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 rate base growth in the utilities segment including through the execution of strategic utility acquisitions and addition of customers; expectations as to AltaGas' ability to maintain financial strength and flexibility, sufficient liquidity, an investment grade credit rating and ready access to capital markets; expectations with respect to in-house construction expertise and competitive advantages of such expertise; 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 for opportunities arising from increased demand in North America for clean sources of power and that AltaGas is in a 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 of continued investment in high growth jurisdictions; AltaGas' ability to achieve a balanced mix of energy infrastructure assets and expected time frame to reach such balance; expectations regarding the locational benefits of the Blythe Facility and site for Blythe II; expectations for growth in the utilities segment as a result of expansion of and investment in existing distribution systems, acquisition of new franchises, fuel switching and development of natural gas storage opportunities; expectations that advancing energy export opportunities will provide higher netbacks to producers; expectations regarding 2017 normalized EBITDA (including expected contributions per business segment and sources of generation); projected growth in normalized EBITDA and normalized funds from operations (including per business segment); 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; expectations for the Cove Point LNG Terminal 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 formations; expected use of proceeds from the issuance of subscription receipts; expectations with respect to the Townsend Facility including, expected earnings and impact on earnings, 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 and cost of compression, and connection capability to North Pine Facility, plans for transport including new NGL pipelines and expected timeline for commercial operations and contribution to earnings; expectations as to timeline for rendering decision on BRFN's application for interlocutory injunction; 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; 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 Alton Natural Gas Storage Project including expected natural gas storage capacity, ability to increase reliability of gas supply to AltaGas' distribution customers in the area, ability to continue working in a constructive manner with stakeholders, construction and brining timeline and storage in service date; expectations with respect to the Montney Gas and Liquids Processing Facilities including design specifications, ownership, location, cost, capacity, access to the CN rail network, transport of propane to the Ridley Island Propane Export Terminal; expectations regarding AltaGas' ability to underpin and nature of contract commitments including with respect to term and dedication, AltaGas' ability to negotiate and execute definitive agreements and receive regulatory approvals, expected timeline for executing definitive agreements and being on-line, AltaGas' expectation that development of this facility will broaden AltaGas'* *customer base and drive continued growth for AltaGas' midstream and energy export strategies; expectations with respect to the development of the Deep Basin NGL facility including stage of development, facility specifications, location, cost, access to rail, connection capability to the proposed Ridley Island Propane Export Terminal, ability to underpin and target for final investment decision, completion of studies and permitting; expectations relating to the Marquette Connector Pipeline including timeline for MPSC approval, construction and in-service date; cost, location, connection capability to existing pipelines and gas supply opportunities; expectations that AltaGas is well-positioned to fund its growth capital and to take advantage of growth opportunities as they arise; expectations relating to AltaGas' ability to fund its projects and business; expectations relating to the energy needs of California; the potential for, and timing of, RFPs from western U.S. states, the ability to bid the Blythe and Sonoran facilities into these upcoming RFPs, and to reconfigure, recontract, use multiple transmission options and pursue other opportunities through bilateral discussions or otherwise; expectations relating to the AltaGas Pomona Energy Storage Project including AltaGas' ability to operate the facility, potential expansion opportunities, potential size of expansion, 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 commercial operations has on AltaGas and on earnings; expectations with respect to the existing Pomona facility including ability to repower, increase capacity, reconfigure, application review process and timeline, ability to bid into future RFPs and pursue other bilateral arrangements or opportunities; expectations relating to the San Joaquin Facilities including expected contributions to growth and impact on earnings; expectations relating to the Northwest Hydro Facilities including expected generation and contributions to earnings and seasonality impacts (including water flow patterns); expected impact on earnings of the Tidewater Gas Asset Disposition; expectations regarding gas processing volumes and disposition of smaller non-core assets; expectations regarding Petrogas including earnings and dividends from Petrogas and contributions to growth of AltaGas; expectations regarding volumes at Ferndale; expectations regarding the U.S. dollar exchange rate, foreign exchange forward contracts, commodity hedge gains, frac spread exposure, recovery in commodity prices, normal seasonal weather and operating and administrative costs; expectations regarding sale of EDS and JFP pipelines including expected closing date and impact on earnings; impact of facility turnarounds on earnings and timing of turnarounds; expected earnings from the utilities segment including from rate base and customer growth, from SEMCO Gas as a result of its Main Replacement Program, from ENSTAR in connection with its 2016 rate case, from Heritage Gas from its customer retention program, higher customer usage, lower interruptible storage service revenue from CINGSA, expected decision date on ENSTAR's rates and impact on EBITDA; expectations regarding stage of appeal process in regards to CINGSA found gas decision; range of customer rate increases for PNG; expectations regarding timeline for implementation of rates for AUI under the second generation PBR plan and timeline for Inuvik Gas to transition ownership; AltaGas' ability to focus on enhancing productivity and streamlining businesses; and expectations regarding the adoption of changes in accounting principles and impact on financial statements.*

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 other factors set out in AltaGas' continuous disclosure documents.

Many factors could cause AltaGas' or any of its business segments' actual results, performance or achievements to vary from those described in this MD&A including, without limitation, those listed above as well as the assumptions upon which they are based proving incorrect. These factors should not be construed as exhaustive. Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, sought, proposed, estimated, forecasted, expected, projected or targeted and such forward-looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A. AltaGas does not intend, and does not assume any obligation, to update these forward-looking statements except as required by law. The forward-looking statements contained in this MD&A are expressly qualified by these cautionary statements.

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

Additional information relating to AltaGas, including its quarterly and annual MD&A and Consolidated Financial Statements, Annual Information Form, and press releases are available through AltaGas' website at www.altagas.ca or through SEDAR at www.sedar.com.

ALTAGAS ORGANIZATION

The businesses of AltaGas are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc.; in regards to the gas business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership and Harmattan Gas Processing Limited Partnership; in regards to the power business, Coast Mountain Hydro Limited Partnership, Blythe Energy Inc. (Blythe), and AltaGas San Joaquin Energy Inc.; and, in regards to the utility business, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), and SEMCO Energy, Inc. (SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

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, natural gas liquids (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 Energy Corp. (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.

2016 GROWTH HIGHLIGHTS

- AltaGas acquired the remaining 51 percent interest in the Edmonton Ethane Extraction Plant (EEEP) effective January 1, 2016;
- On May 24, 2016, AltaGas LPG Limited Partnership, a wholly-owned subsidiary, entered into a Memorandum of Understanding with Astomos Energy Corporation (Astomos) setting out key commercial terms for the sale and purchase of liquefied petroleum gas (LPG) from the Ridley Island Propane Export Terminal. In October 2016, approval was

received from the National Energy Board (NEB) for a 25-year licence to export up to 1.35 million tonnes per annum of propane;

- Commercial operations commenced in the third quarter of 2016 at the integrated midstream complex at Townsend in northeast British Columbia, including the 198 Mmcf/d shallow-cut gas processing facility (the Townsend Facility), gas gathering line, NGL egress pipelines and truck terminal;
- In October 2016, the Board of Directors approved a positive Final Investment Decision (FID) for the construction, ownership and operation of the North Pine NGL Separation Facility (the North Pine Facility);
- On December 15, 2016, SEMCO Gas filed an application with the Michigan Public Service Commission (MPSC) seeking approval to construct, own, and operate the Marquette Connector Pipeline (the MCP). The cost of the MCP is estimated at approximately US$135 to $140 million;
- On December 16, 2016, AltaGas received permits for the construction of the North Pine Pipelines from the British Columbia Oil and Gas Commission (BCOGC);
- On December 19, 2016, AltaGas received regulatory approval from the BCOGC for the doubling of the Townsend Facility to 396 Mmcf/d and to retrofit the existing 198 Mmcf/d shallow-cut Townsend Facility to a deep-cut facility at a future date; and
- On December 31, 2016, the 20 MW energy storage facility at Pomona, California (the Pomona Energy Storage Facility) began commercial operations under the terms of the Energy Storage Resource Adequacy Purchase Agreement (ESA) with Southern California Edison (SCE).

2016 FINANCIAL HIGHLIGHTS

(Includes non-GAAP financial measures; see discussion in Non-GAAP Financial Measures section of this MD&A)

- Normalized EBITDA was $701 million, an increase of 20 percent compared to $582 million in 2015;
- Normalized funds from operations were $554 million ($3.52 per share), an increase of 18 percent compared to $470 million ($3.41 per share) in 2015;
- Net income applicable to common shares was $155 million ($0.99 per share) compared to $10 million ($0.07 per share) in 2015;
- Normalized net income was $153 million ($0.98 per share), an increase of 9 percent compared to $140 million ($1.02 per share) in 2015;
- Net debt was $3.9 billion as at December 31, 2016, consistent with December 31, 2015;
- Debt-to-total capitalization ratio was 46 percent as at December 31, 2016, compared to 48 percent as at December 31, 2015;
- On February 29, 2016, AltaGas completed the sale to Tidewater Midstream and Infrastructure Ltd. (Tidewater) 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 gross consideration of $30 million of cash and approximately 43.7 million common shares of Tidewater (the Tidewater Gas Asset Disposition);
- On April 7, 2016, AltaGas issued $350 million of senior unsecured medium-term notes (MTNs). The MTNs carry a coupon rate of 4.12 percent and will mature on April 7, 2026;
- 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;
- In June 2016, AltaGas completed a restructuring that reduced its total non-utility workforce by approximately 10 percent (the Workforce Restructuring). Total pre-tax restructuring costs incurred were approximately $7 million. On an annualized basis, operating and administrative expenses are expected to be reduced by approximately $7 million;
- On June 29, 2016, AltaGas directly invested $150 million to subscribe for 6,000,000 cumulative redeemable convertible preferred shares (the Petrogas Preferred Shares) of Petrogas Energy Corp. (Petrogas). These Petrogas Preferred Shares are non-voting and entitle AltaGas to a fixed, cumulative, preferential cash dividend at a rate of 8.5 percent per annum payable quarterly;
- On July 20, 2016, the Board of Directors approved an increase in the monthly dividend by $0.01 per common share to $0.175 ($2.10 per common share annualized) effective for the August dividend, a 6.1 percent increase;

- In July 2016, the Regulatory Commission of Alaska (RCA) approved an interim refundable rate increase for ENSTAR effective August 1, 2016 with final rates to be set in 2017;
- In September 2016, the Nova Scotia Utility and Review Board (NSUARB) approved Heritage Gas' Customer Retention Program;
- On December 8, 2016, AltaGas extended the maturity of its $1.4 billion syndicated credit facility by one year to December 15, 2020 and obtained a new US$300 million extendible revolving term credit facility with certain financial institutions with a maturity date of December 8, 2019; and
- In March 2016, ASTC Power Partnership (ASTC), a joint venture of AltaGas Pipeline Partnership and TransCanada Energy Ltd. gave notice to the Balancing Pool to terminate the Sundance B Power Purchase Arrangements for Sundance B Unit 3 and Unit 4 (collectively, the Sundance B PPAs). On December 16, 2016, AltaGas Pipeline Partnership and the Government of Alberta (GOA) reached a definitive settlement agreement regarding the termination of the Sundance B PPAs.

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.

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 a lower cost. On January 25, 2017, the Corporation announced its pending acquisition of WGL Holdings, Inc. (WGL). 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 terminal 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 the pending acquisition of WGL can be found in the *Recent Developments* section of this MD&A.

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 complementary 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 business, with a focus on distributed generation and energy efficiency assets throughout the United States. WGL also owns a retail gas and power marketing business serving approximately 260,000 customers across five states in the U.S. Further information on the pending acquisition of WGL can be found in the *Recent Developments* section of this MD&A.

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 pending acquisition of WGL, which is the sole common shareholder of Washington Gas Light Company (Washington Gas), a regulated natural gas utility headquartered in Washington, D.C., serving more than 1.1 million customers in Maryland, Virginia, and the District of Columbia can be found in the *Recent Developments* section of this MD&A.

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

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

Owning and Operating Energy Infrastructure

Natural gas supply and demand fundamentals and the demand for clean energy have consistently underpinned the Corporation's strategy. In recent years, the supply and demand fundamentals have been changing. Abundant supply of natural gas in North America, driven by new technology that has improved the economics of unconventional gas plays, has been positive news for North American energy consumers and has led to renewed interest in natural gas as an economically priced, clean-burning fuel. As a result, the use of natural gas for power generation, household, and commercial and industrial 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 Kosan Co.,Ltd. (Idemitsu) who owns 51 percent of Astomos, the largest LPG importer in Japan (Mitsubishi Corporation owns the remaining 49 percent of Astomos).

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 California Independent System Operator (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.

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.

Maintain Financial Strength and Flexibility

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.

Continue to Develop Organizational Capability to Support the Strategy

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

Several changes at the executive level were made in 2016 due to planned retirements. Succession plans are in place to ensure continuity and a smooth transition to position the Corporation for its next phase of growth.

STRATEGY EXECUTION

AltaGas has successfully executed its strategy to create shareholder value and to maintain financial strength and flexibility, growing from under $4 billion in assets five years ago to total assets of over $10 billion at the end of 2016. In the last five years, the Corporation has reported a 21 percent compound annual growth rate in normalized EBITDA and a 9 percent compound annual growth rate in dividends per share. AltaGas delivers an effective balance between yield and growth. The pending acquisition of WGL supports AltaGas' long-term vision by reinforcing AltaGas' strategy of focusing on high quality, low risk and long-lived assets to achieve a diversified long-term growing business mix. The pending acquisition is expected to accelerate the Corporation's growth to combined total assets of over $22 billion, an estimated $4.5 billion in natural gas rate base assets, and total utilities customers of approximately 1.7 million. AltaGas expects to continue investing in attractive high growth jurisdictions and is focused on achieving a balanced mix of energy infrastructure assets over the medium to long term. The attractive growth prospects in each of WGL's regulated utility, midstream energy services and commercial energy system business lines, of which the large majority are regulated and/or under long-term contracts, is complementary to AltaGas' long-term vision. Please refer to the *Recent Developments* section of this MD&A for further information.

AltaGas continues to drive its strategy to grow its highly contracted, clean power generation portfolio. 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. In the fourth quarter of 2016, AltaGas safely commissioned the Pomona Energy Storage Facility, located at the existing Pomona facility in the east Los Angeles Basin of Southern California. At commissioning, the lithium-ion battery facility was the largest of its kind in North America and was constructed in direct response to the California Public Utilities Commission (CPUC) mandated expedited procurement of large-scale, grid-connected energy storage resources to deal with the distinct possibility of electricity service interruptions caused by the Aliso Canyon shutdown. The Pomona Energy Storage Facility is contracted under a 10-year ESA with SCE whereby AltaGas will receive fixed monthly resource adequacy payments and will retain the rights to earn additional revenue from the energy and ancillary services provided by the lithium-ion batteries. 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. The success of the Pomona Energy Storage Facility establishes the Corporation's presence as a leader in a growing energy storage industry as well as showcases AltaGas' ability to execute on its strategy, being well positioned to take advantage of the changing energy landscape in the California market, while making use of a brownfield site as AltaGas continues to work on reconfiguring the existing 44 MW Pomona gas-fired facility.

Continued enhancements have been made to AltaGas' $1 billion investment in the Northwest Hydro Facilities, including numerous operational and mechanical facility improvements focused on increased efficiency and reliability. The continued improvements particularly at Forrest Kerr enhance value by positioning the assets to operate under a wider variety of environmental conditions. In 2016 the facilities showed productivity growth of greater than 15 percent, and though seasonally lower fall volumes limited total output, the facilities entered 2017 better positioned to deliver incremental generation.

AltaGas continues to progress its integrated northeast British Columbia strategy on several different fronts. Construction was completed at the Townsend Facility ahead of schedule and under budget and this major new asset entered service in July 2016. In October 2016, AltaGas announced FID for the North Pine Facility, a NGL separation and handling facility near Fort St. John, British Columbia, which will handle liquids from both Townsend and other producers in the Montney region. The site is well connected by rail and ideally situated to supply the Ridley Island Propane Export Terminal. AltaGas strives to meet producer needs for new markets and higher netbacks by advancing energy export projects. On January 3, 2017, AltaGas announced a positive FID for the construction of the Ridley Island Propane Export Terminal, a propane export terminal on Ridley Island near Prince Rupert, British Columbia. This propane export facility is expected to be the first LPG export terminal off the west coast of Canada, and is being designed to ship up to 1.2 million tonnes per annum. Please refer to the *Growth Capital* section in this MD&A for further details regarding these projects.

Across the five separate utility franchises throughout North America, AltaGas continues to focus on safely and reliably delivering customers clean, affordable energy. In 2016 AltaGas achieved customer growth across all utilities, and grew rate base by expanding its existing infrastructure through system upgrade programs and organic growth opportunities.

In 2016, the Corporation enhanced its financial strength and flexibility through a combination of internally-generated cash flows, the Premium Dividend[TM], Dividend Reinvestment and Optional Cash Purchase Plan (DRIP), and the issuance of approximately $790 million of equity and long-term debt. During the year, AltaGas issued approximately $440 million of common shares, and $350 million of medium-term notes. AltaGas maintained sufficient liquidity and a strong balance sheet throughout the year and exited 2016 with approximately $1.6 billion of available credit facilities and debt-to-total capitalization of 46 percent. AltaGas entered 2017 well positioned to fund its growth capital and to take advantage of growth opportunities such as the pending acquisition of WGL. Please refer to the *Recent Developments* section of this MD&A.

During 2016, the Board of Directors approved a dividend increase of approximately 6 percent from $1.98 per share to $2.10 per share on an annualized basis. The dividend increase reflects the success of AltaGas' recent asset additions across all business segments, as well as the stability and sustainability of its cash flows.

2017 OUTLOOK

AltaGas currently expects to deliver approximately high single digit percentage normalized EBITDA growth in 2017 compared to 2016. All three business segments are expected to drive the annual growth in 2017, with the Gas segment expecting to generate the highest EBITDA growth, followed by the Power segment and the Utilities segment. The Power and Utilities segments are expected to generate approximately 75 percent of 2017 normalized EBITDA. The following are the key drivers contributing to the expected EBITDA growth in 2017:

- First full year of commercial operations at the Townsend Facility;
- Higher earnings from frac exposed volumes as a result of the expected recovery in commodity prices;
- Contributions from the Pomona Energy Storage Facility, which entered commercial operation on December 31, 2016;
- Higher expected earnings from the Northwest Hydro Facilities due to continual improvements in operational efficiency and expected contractual price increases;
- Higher expected earnings from Petrogas, including a full year of income from the Petrogas Preferred Share dividends;
- Normal seasonal weather in 2017 compared to unfavorable weather in 2016;
- Decrease in operating and administrative expenses as a result of various cost savings initiatives, including the savings from the Workforce Restructuring that occurred in 2016; and
- Partial contributions from Townsend Phase 2 entering commercial operations in the fourth quarter of 2017.

The overall forecasted EBITDA growth in 2017 includes an anticipated asset sale of the Ethylene Delivery Systems (EDS) and the Joffre Feedstock Pipeline (JFP) transmission assets to Nova Chemicals Corporation (Nova Chemicals) and scheduled turnarounds at the EEEP and Gordondale facilities in 2017.

Normalized funds from operations are also expected to increase by approximately high single digit percentage growth driven by the same factors noted above for normalized EBITDA growth, partially offset by higher current tax expenses and lower common share dividends from Petrogas, as Petrogas is expected to retain a portion of its cash to fund its capital program and for general corporate purposes.

As part of the financing strategy for the WGL Acquisition, certain asset sales may be undertaken in 2017, subject to market conditions (see *Recent Developments* Section of this MD&A for further information). Any such asset sales, if undertaken, may adversely impact the 2017 outlook for normalized EBITDA and normalized funds from operations, depending on when such sales close during the year.

[TM] Denotes trademark of Canaccord Genuity Corp.

In the Gas segment, additional earnings in 2017 are expected to be driven by a full year of contributions from the Townsend Facility, higher frac exposed volumes and commodity prices, higher earnings from Petrogas due to improved profitability in the base business, higher volumes expected at the Ferndale Terminal, a full year of income from the Petrogas Preferred Share dividends, and a partial year contribution from Townsend Phase 2 entering commercial operations in the fourth quarter of 2017. The additional earnings are expected to be offset by the closing of an anticipated sale of the EDS and JFP transmission pipelines in the first quarter of 2017, and scheduled turnarounds at the Gordondale and EEEP facilities in mid-2017. Based on current commodity prices, AltaGas estimates an average of approximately 9,600 Bbls/d will be exposed to frac spreads prior to hedging activities. For 2017, AltaGas has frac hedges in place for approximately 5,450 Bbls/d at an average price of approximately $23/Bbl excluding basis differentials.

In the Power segment, increased earnings are expected to be driven by contributions from the Pomona Energy Storage Facility, higher expected earnings from the Northwest Hydro Facilities as improvements in productivity continue and contractual price increases take effect, and lower planned outages expected at Blythe. The earnings and cash flows from the Northwest Hydro Facilities are expected to be seasonally stronger beginning in the second quarter through the end of the third quarter and are expected to decline in the fourth quarter based on seasonal water flow patterns. Actual seasonal water flows will vary with regional temperatures and precipitation levels.

In the Utilities segment, AltaGas expects to continue to benefit from the normal seasonally strong first and fourth quarters due to the winter heating season. The Utilities segment is expected to report increased earnings in 2017 mainly driven by the significantly warmer than normal weather experienced at all of the Utilities in 2016, whereas the outlook for 2017 assumes normal weather, and higher customer usage at certain of the Utilities, partially offset by lower interruptible storage service revenue at CINGSA. Earnings at all of the Utilities (except PNG) are affected by weather in their franchise areas, with colder weather generally benefiting earnings. If the weather varies from normal weather, earnings at the utilities would be affected. In addition, earnings from the Utilities segment are impacted by regulatory decisions and the timing of these decisions. In 2017, ENSTAR expects EBITDA to increase by approximately $3 million as a result of the interim refundable rate increase approved in 2016 by the RCA, with final rates expected to be set in the third quarter of 2017.

Earnings generated from AltaGas' U.S. assets are exposed to fluctuations in the U.S./Canadian dollar exchange rate, with the strengthening of the U.S. dollar having a positive impact on earnings. However, some of this benefit will be offset by AltaGas' U.S. dollar denominated debt and preferred shares.

SENSITIVITY ANALYSIS

AltaGas' financial performance is affected by factors such as changes in commodity prices, exchange rates and weather. The following table illustrates the approximate effect of these key variables on AltaGas' expected normalized EBITDA for 2017.

Factor	Increase or decrease	Approximate impact on normalized EBITDA *($ millions)*
Natural gas liquids fractionation spread(1)	$1/Bbl	2
Degree day variance from normal - Canadian utilities(2)	5 percent	2
Degree day variance from normal - U.S. utilities(3)	5 percent	5
Change in CAD per US$ exchange rate	$0.05	15

(1) Based on approximately 50 percent of frac spread exposed NGL volumes being hedged.

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

(3) Degree days - U.S. utilities relate to SEMCO Gas and ENSTAR service areas. For U.S. utilities degree days are a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Gas and during the prior 10 years for ENSTAR.

RECENT DEVELOPMENTS

Pending Acquisition of WGL Holdings, Inc.

On January 25, 2017, the Corporation entered into a definitive agreement (the Merger Agreement) to indirectly acquire WGL Holdings, Inc. (NYSE:WGL) (the WGL Acquisition). Pursuant to the Merger Agreement, following the consummation of the WGL Acquisition, WGL common shareholders will receive US$88.25 per common share in cash, which represents a total enterprise value of $8.4 billion, including the assumption of approximately $2.4 billion of debt as at September 30, 2016.

WGL is a diversified energy infrastructure company and the sole common shareholder of Washington Gas, a regulated natural gas utility headquartered in Washington, D.C., serving more than 1.1 million customers in Maryland, Virginia, and the District of Columbia. WGL has a growing midstream business with investments in natural 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 terminal in Maryland being developed by a third party, currently expected to be operational in late 2017. WGL also owns contracted clean power assets, with a focus on distributed generation and energy efficiency assets throughout the United States. In addition, WGL has a retail gas and power marketing business with approximately 260,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. Upon completion of the WGL Acquisition, AltaGas will have over $22 billion of assets and more than 1.7 million rate regulated gas customers.

The WGL Acquisition is not subject to any financing contingency. AltaGas expects that cash to close the WGL Acquisition will be provided from a combination of the net proceeds from a $400 million private placement of subscription receipts to OMERS, the pension plan for Ontario's municipal employees, and a bought deal subscription receipt offering for gross proceeds of approximately $2.1 billion (see *Subscription Receipts* section below), subsequent offerings of senior debt, hybrid securities, equity or equity-linked securities (including Preferred Shares or convertible debentures), select AltaGas asset sales and through a fully committed US$3.1 billion bridge facility, which would be available for 12 to 18 months following closing of the WGL Acquisition. AltaGas believes there are a number of attractive, actionable opportunities to monetize certain of its assets in a manner which supports the Corporation’s long term strategy of growing in attractive areas and maintaining a long term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. The timing of these subsequent offerings and asset sales is subject to prevailing market conditions, but are expected to be completed prior to the closing of the WGL Acquisition.

The WGL Acquisition is subject to certain closing conditions, including approval of WGL common shareholders and certain regulatory and government approvals, including approval by the Public Service Commission of the District of Columbia, The Maryland Public Service Commission, The Commonwealth of Virginia State Corporation Commission, the United States Federal Energy Regulatory Commission, and the Committee on Foreign Investment in the United States, and expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

Subscription Receipts

On February 3, 2017, the Corporation issued approximately 80.7 million subscription receipts to partially fund the WGL Acquisition at a price of $31 each for total gross proceeds of approximately $2.5 billion. Each subscription receipt entitles the holder to automatically receive one common share upon closing of the WGL Acquisition. While the subscription receipts remain outstanding, holders will be entitled to receive cash payments (Dividend Equivalent Payments) per subscription receipt that are equal to dividends declared on each common share. Such Dividend Equivalent Payments will have the same record date as the related common share dividend and will be paid to holders of the subscription receipts concurrently with the payment date of each such common share dividend. The Dividend Equivalent Payments will be paid first out of any interest on the escrowed funds and then out of the escrowed funds. If the Merger Agreement is terminated after the common share dividend declaration date, but before the common share dividend record date, subscription receipt holders of record on the termination date shall receive a pro-rata payment of the dividend as the Dividend Equivalent Payment. If the Merger Agreement is terminated on a record date or following a record date but on or prior to the dividend payment date, holders will be entitled to receive the full Dividend Equivalent Payment.

The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of WGL and confirmation that 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, but for the payment of the purchase price, and AltaGas has available to it all other funds required to complete the WGL Acquisition. If the escrow release notice and direction is not delivered on or prior to 5:00 pm (Calgary time) on September 4, 2018, the Corporation will be required to make a termination payment equal to the aggregate issue price of such holder's subscription receipts plus any unpaid Dividend Equivalent Payments owing to such holder of subscription receipts.

GROWTH CAPITAL

Based on projects currently under review, development or construction, AltaGas expects capital expenditures in the range of $550 to $650 million for 2017. AltaGas' Gas segment will account for approximately 65 to 75 percent of the total capital expenditures, while AltaGas' Utility segment will account for approximately 20 to 25 percent and the Power segment will account for approximately 5 to 10 percent. Gas and Power maintenance capital is expected to be approximately $25 to $35 million of the total capital expenditures in 2017. The majority of AltaGas' capital expenditures relating to its Gas segment will be allocated towards AltaGas' growth projects including the Ridley Island Propane Export Terminal, Townsend Phase 2, the North Pine Facility, the North Pine Pipelines, and the new Montney Gas and Liquids Processing Facilities. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets. Larger asset sales may also be considered subject to market conditions as part of the WGL Acquisition financing strategy (see *Recent Developments* section of this MD&A).

AltaGas' 2017 committed capital program is expected to be funded through internally-generated cash flow and the DRIP. If required, the Corporation also has sufficient borrowing capacity available under its credit facilities, as well as access to capital markets.

Townsend Gas Processing Facility Expansion

AltaGas is developing an expansion (Townsend Phase 2) of the existing Townsend Facility. 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. The estimated cost of the first train of Townsend Phase 2 will be approximately $80 million and with the addition of incremental field compression equipment to move raw gas production from the Blair Creek area to Townsend, the estimated total cost will be approximately $120 to $140 million. 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 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. 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.

North Pine NGL Project

On October 19, 2016, the Board of Directors approved a positive FID for the construction, ownership and operation of the North Pine Facility to be located approximately 40 km northwest of Fort St. John, British Columbia. 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 propane from the North Pine Facility to the Ridley Island Propane Export Terminal. The permit from the BCOGC to construct, own and operate the North Pine Facility was issued on September 23, 2016. AltaGas will be constructing the North Pine Facility with two separate NGL separation trains each capable of processing up to 10,000 Bbls/d of propane plus NGL mix (C3+), for a total of 20,000 Bbls/d. The first phase will also include 6,000 Bbls/d of condensate (C5+) terminalling capacity, with ultimate capacity for up to 20,000 Bbls/d. The second 10,000 Bbls/d NGL separation train is expected to follow after completion of the first train, subject to sufficient commercial support from area producers.

Two eight inch diameter NGL supply pipelines (the North Pine Pipelines), each approximately 40 km in length, will also be constructed and will run from AltaGas' existing Alaska Highway truck terminal (the Truck Terminal) to the North Pine Facility. One supply line will carry C3+ with the other carrying C5+. At the Truck Terminal, the existing Townsend NGL Egress Pipelines currently delivering product from AltaGas' Townsend Facility will be connected to the North Pine Pipelines to enable shipment of NGL produced at the Townsend Facility directly to the North Pine Facility. The BCOGC permit for the North Pine Pipelines was received on December 16, 2016. 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.

The capital cost of the first train and associated pipelines is estimated to be approximately $125 to $135 million. This investment will be backstopped by long-term supply agreements with Painted Pony for a portion of the total capacity, and will include dedication of all of Painted Pony's NGL produced at the Townsend and Blair Creek facilities.

On August 8, 2016, Blueberry River First Nations (BRFN) applied for an interlocutory injunction restraining the Province of British Columbia from, among other things, permitting oil and gas activities within BRFN's traditional territory in northeast British Columbia pending resolution of an earlier BRFN action alleging breaches by the Province of British Columbia of BRFN's treaty rights. In the unlikely event the injunction is granted, there could be potential reduction in the future volumes of natural gas available for processing at AltaGas' facilities in this area, although it is AltaGas' understanding that any such exposure is limited. Furthermore, AltaGas does not expect that an injunction will cause delays in the construction of Townsend Phase 2, the North Pine Facility and the North Pine Pipelines as such projects have received approval to construct these facilities from the BCOGC. The interlocutory injunction was heard from October 31, 2016 to November 4, 2016 and it is expected that a decision on the injunction will be rendered in the first quarter of 2017.

Ridley Island Propane Export Terminal

On January 3, 2017, AltaGas reached a positive FID on the Ridley Island Propane Export Terminal, having received approval from federal regulators. AltaGas has executed long-term agreements securing land tenure along with rail and marine infrastructure on Ridley Island, and will proceed with the construction, ownership and operation of 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. Propane from British Columbia and Alberta will be transported to the facility using the existing CN rail network. The Ridley Island Propane Export Terminal is estimated to cost approximately $450 to $500 million and is to be designed to ship 1.2 million tonnes of propane per annum. 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.

Based on production from its existing facilities and forecasts from new plants under construction and in active development, AltaGas anticipates having physical volumes equal to approximately 50 percent of the 1.2 million tonnes. The remaining 50 percent is expected 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.

On May 24, 2016, AltaGas LPG Limited Partnership, a wholly owned subsidiary, 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 off-takers for further capacity commitments are proceeding.

AltaGas began the formal environmental review process in early 2016, which included submission of the Environmental Evaluation Document, review and final determination by federal regulators under terms and conditions that will allow the project to proceed. AltaGas has engaged and worked closely with First Nations throughout the process and will continue to do so as it moves forward with the Ridley Island Propane Export Terminal.

Construction is expected to begin in the first quarter of 2017 and will proceed under the self-perform model successfully used by AltaGas to build its other projects on time and on budget. The Ridley Island Propane Export Terminal is expected to be in service by the first quarter of 2019.

Alton Natural Gas Storage Project

In January 2016, the Government of Nova Scotia issued permits to resume construction of the Alton Natural Gas Storage Project, located near Truro, Nova Scotia. To allow more time for discussions and public engagement, AltaGas deferred major civil construction until summer 2016. Construction resumed on July 5, 2016 and brining for cavern development is now scheduled for 2017. On January 30, 2017, the Supreme Court of Nova Scotia released a decision setting aside the Minister of Environment's (the Minister) April 18, 2016 decision to dismiss an appeal by Sipekne'katik First Nation (SFN) regarding an Industrial Approval (IA) which was issued by the Minister. The Supreme Court has ordered the matter be referred back to the Minister for further action. The IA remains in effect for the Alton Natural Gas Storage Project and the Supreme Court did not issue a stay against further project work. AltaGas continues to work constructively with the Government of Nova Scotia and SFN. The Alton Natural Gas Storage Project is expected to provide up to 10 Bcf of natural gas storage capacity. Storage service is expected to commence in 2020.

Montney Gas and Liquids Processing Facilities

In January 2017, AltaGas entered into a non-binding Letter of Intent (LOI) with a significant Montney producer to construct a 120 Mmcf/d deep-cut natural gas processing facility and a NGL separation train, capable of processing up to 10,000 Bbls/d of NGL mix, and a rail terminal (the Montney Facilities). The Montney Facilities, which are to be located in another area of the Montney separate from AltaGas' current operations, are expected to have access to the CN rail network allowing for the transportation of propane to the Ridley Island Propane Export Terminal. Under the terms of the LOI, it is contemplated that the deep-cut processing facility will be jointly owned, while the NGL separation train and rail terminal will be fully owned by AltaGas. The deep-cut processing facility is expected to cost approximately $100 to $110 million while the NGL separation train and rail terminal are expected to cost approximately $60 to $70 million. It is expected that the deep-cut facility will be underpinned with long-term take-or-pay and dedication commercial agreements. Completion of the project is subject to, among other things, negotiation and execution of definitive agreements, which AltaGas targets to have signed within the first quarter of 2017. Subject to regulatory approvals, the Montney Facilities are expected to be on-line in early 2019.

Early Stage Deep Basin NGL Facility

AltaGas is in the early stages of development of a site in the Deep Basin region of northwest Alberta. AltaGas plans to develop NGL facilities that would serve producers in this region. The NGL facilities will have access to existing rail and can be connected to AltaGas' Ridley Island Propane Export Terminal. Active discussions with producers to contractually underpin the facility are continuing, and engagement with First Nations and key stakeholders is underway. FID is subject to completing commercial arrangements, stakeholder engagement, and regulatory approvals. Depending upon the final designs and components, the facility is expected to cost approximately $30 to $80 million.

Marquette Connector Pipeline

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. The MCP is estimated to cost between US$135 to $140 million with an anticipated in service date in 2020.

Blythe Energy Center (Blythe)

The Blythe Facility, and the Blythe II Facility (Sonoran) currently under development, are well situated to serve a larger western regional transmission organization comprised of several western U.S. states. AltaGas expects several RFPs to emerge from these states throughout 2017 and beyond, and expects to bid both the potential re-contracting of its Blythe Facility after its Power Purchase Agreement (PPA) expires July 31, 2020, and the potential Sonoran Facility, into these upcoming RFPs. Separately, AltaGas continues to have bilateral discussions with utilities, municipalities, and corporations for multi-year capacity agreements, while also considering Resource Adequacy market pricing, potential energy and ancillary service offerings, and alternative configurations (gas, combined with solar and energy storage) for the Blythe facilities using the multiple transmission options and capacity available to best serve AltaGas' potential customers in the desert southwest, as the demand for clean energy increases. It is expected that up to 15,000 megawatts (MW) will need to be replaced in California due to retirements over the next decade. As utilities, non-utilities and large generators continue to determine their future resource needs to achieve California's 50 percent renewable portfolio standard, sufficient flexible, fast ramping gas-fired capability will be required to help backstop intermittent, non-dispatchable, low capacity factor renewable energy sources and meet peak load requirements.

Pomona Facility

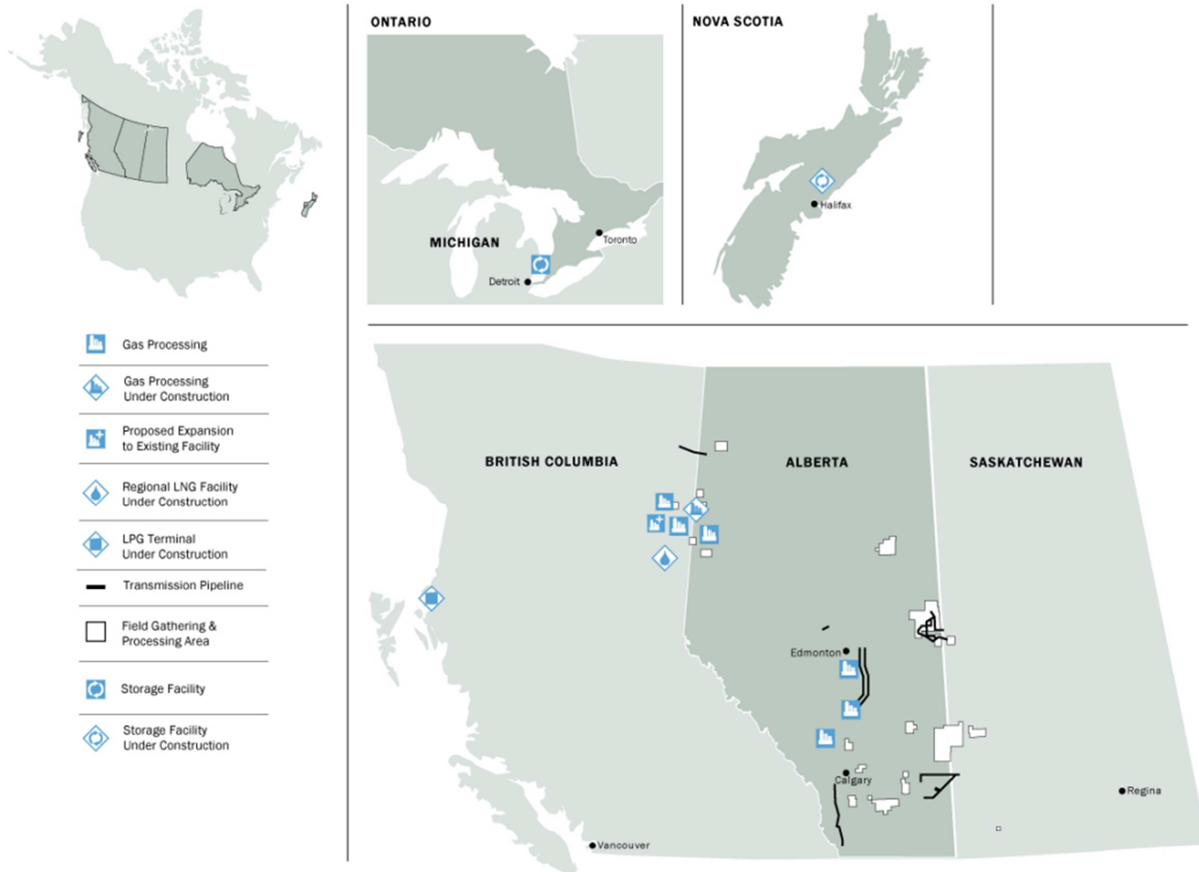
AltaGas is continuing to work on reconfiguring the existing Pomona facility. In the first quarter of 2016, AltaGas, through its subsidiary AltaGas Pomona Energy Inc., submitted an application with the California Energy Commission (CEC) to repower the Pomona facility to a flexible, fast ramping peaking facility under the small power plant exemption process. It is anticipated that the CEC will complete the application review process in 2017, which will be followed by the City of Pomona and local air district permitting processes. The existing Pomona facility is a 44.5 MW gas-fired peaking plant strategically located in the east Los Angeles Basin load pocket. The repowered facility could be comprised of more efficient gas-fired technology with capacity of up to 100 MW. Following approval, AltaGas will be ready to bid the proposed reconfigured facility into upcoming RFPs or enter into other bilateral contract arrangements. In parallel with the repowering proposal, AltaGas will evaluate a mutually exclusive expansion of the Pomona Energy Storage Facility based on SCE's need for additional energy storage at the site which could readily accommodate another 20 MW of lithium-ion batteries.

GAS

Description of Assets

AltaGas' Gas segment serves customers primarily in the WCSB and transacts more than 2 Bcf/d of natural gas including natural gas gathering and processing, NGL extraction and separation, transmission, storage, and natural gas and NGL marketing. Gas gathering systems move natural gas from producing wells to processing facilities where impurities and certain hydrocarbon components are removed. The gas is then compressed to meet downstream pipelines' operating specifications for transportation. Extraction and separation facilities reprocess natural gas to extract and recover ethane and NGL. As at December 31, 2016, AltaGas owned approximately 1.7 Bcf/d of extraction processing capacity and approximately 1.1 Bcf/d of raw field gas processing capacity. The Gas segment also includes an equity investment in Petrogas through AIJVLP.

Transmission pipelines deliver natural gas and NGL to distribution systems, end-users or other downstream pipelines. AltaGas uses its market knowledge and expertise to create value by buying and reselling natural gas; providing gas transportation, storage, and gas and NGL marketing for producers; and sourcing gas supply for some of the Corporation's processing assets. The Gas segment also includes several expansion and greenfield projects under development, specifically in northeast British Columbia, and energy export projects.



Specifically, the Gas segment includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1.7 Bcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues. With the acquisition of the remaining 51 percent interest in EEEP effective January 1, 2016, the total net licensed inlet capacity increased by 0.1 Bcf/d. However, the Empress Gas Liquids Joint Venture (EGLJV) plant began decommissioning in late 2016, decreasing the total net licensed inlet capacity by 0.1 Bcf/d. The natural gas supply to AltaGas' extraction plants, with the exception of Harmattan and Younger extraction plants, depends on natural gas demand pull from residential, commercial and industrial usage inside and outside of Western Canada, and gas liquids demand pull from the Alberta petrochemical market and propane heating. Natural gas supply to Younger extraction plant (Younger) is dependent on the amount of raw natural gas processed at the McMahon gas plant, which is based on the robust natural gas producing region of northeastern British Columbia. Harmattan's raw natural gas supply is based on producer activity in the west-central region of Alberta. Harmattan is the only deep-cut and full fractionation plant in the area;
- Four natural gas transmission systems with combined transportation capacity of approximately 0.6 Bcf/d and NGL pipelines with combined capacity of 189,300 Bbls/d. The transmission assets provide stable take-or-pay based revenues. In 2014, Nova Chemicals provided notice that it intends to exercise its option to purchase the EDS and JFP transmission assets in March 2017;
- Approximately 30 gathering and processing facilities in Western Canada and a network of approximately 5,300 km of gathering and sales lines that gather natural gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets. The field facilities provide fee-for-service revenues based on volumes processed as well as revenues based on take-or-pay contracts. A significant portion of contracts flow through operating costs to the producers;
- 50 percent ownership of the 5.3 Bcf Sarnia natural gas storage facility connected to the Dawn Hub in Eastern Canada;
- The Alton Natural Gas Storage Project under construction;

- Natural gas and NGL marketing and gas transportation services to optimize the value of the infrastructure assets and meet customer needs;
- 50 percent ownership in AIJVLP, with the remaining 50 percent owned by Idemitsu;
- AIJVLP holds a two-thirds ownership interest in Petrogas, a leading North American integrated midstream company, with an extensive logistics network consisting of over 1,800 rail cars and 24 rail and truck terminals providing key infrastructure, supply logistics and marketing expertise. Petrogas also owns the Ferndale Terminal, which is operated by AltaGas;
- A 15-year strategic alliance between AltaGas and Painted Pony for the development of processing infrastructure and marketing services for natural gas and NGL. In the first phase of the strategic alliance, the 198 Mmcf/d Townsend Facility and associated infrastructure entered commercial operations in the third quarter of 2016. AltaGas is the operator of the Townsend Facility and will also be the marketer for Painted Pony's gas and NGL. In addition, AltaGas is developing Townsend Phase 2, which is expected to enter commercial operations in the fourth quarter of 2017. It is expected that Townsend Phase 2 will be fully contracted with Painted Pony;
- The Ridley Island Propane Export Terminal in British Columbia under construction;
- The North Pine Facility and North Pine Pipelines near Fort St. John, British Columbia under construction;
- The new Montney Facilities under development; and
- A small liquefied natural gas (LNG) facility in Dawson Creek, British Columbia under construction.

Please refer to the *Growth Capital* section in this MD&A for further details regarding Townsend Phase 2, the Ridley Island Propane Export Terminal, the North Pine Facility and North Pine Pipelines, the Montney Facilities, and the Alton Natural Gas Storage project.

Capitalize on Opportunities

AltaGas plans to grow its gas business by expanding and optimizing strategically-located assets and by adding new assets to serve customers by providing access to new markets, including Asia. New infrastructure is expected to be larger scale facilities supporting the vast reserves in the WCSB. AltaGas' strategic investment in Petrogas enhances the services provided by the Gas segment by offering integrated midstream services to AltaGas' customers and by creating long-term value for the Gas segment. While providing safe and reliable service, AltaGas pursues opportunities in the Gas segment to deliver value to its customers and enhance long-term shareholder value. The Corporation's objectives are to:

- Capitalize on the infrastructure growth opportunities associated with growing natural gas and liquids supply in the WCSB;
- Provide a fully-integrated midstream service offering including pipeline, liquefaction, and refrigeration facilities to its customers across the energy value chain, with higher producer netbacks resulting from export access to higher value markets, including Asia;
- Maintain strong relationships with local communities, First Nations, governments, and regulatory bodies;
- Maximize profitability of existing facilities by increasing capacity, utilization and efficiency;
- Mitigate volume risk through contractual structures, redeployment of equipment and expansion of geographic reach;
- Coordinate between facilities, business segments and product lines to improve efficiencies and maximize profits; and
- Expand into new natural gas infrastructure markets such as regional liquefied natural gas (RLNG).

In recent years, the WCSB has changed from a maturing basin to one capable of sustainable long-term growth via new low cost gas formations such as the Montney. The emergence of unconventional gas plays in the WCSB such as the Montney, as well as increased focus on horizontal multi-fracturing and completions technology, have resulted in abundant natural gas supply and associated liquids. Market demand, including the demand generated from the LPG and potential LNG export projects on the west coast of North America, provides significant long-term growth opportunities for the Corporation's Gas segment. AltaGas expects to capitalize on these opportunities by increasing throughput at facilities, by increasing interests in existing plants, and by acquiring and constructing new facilities such as liquefaction, refrigeration, natural gas processing, extraction, separation, storage and transmission pipelines. AltaGas' 15-year strategic alliance with Painted Pony is an example of the Corporation's ability to partner with producers to provide a fully-integrated service offering. Another example of this is AltaGas' recently announced opportunity whereby AltaGas would build the Montney Facilities for a new potential customer in the Montney area, while providing both value-added services and connectivity to different end markets, including the Ridley Island Propane Export Terminal. This opportunity would further expand AltaGas' footprint in the prolific Montney gas play as AltaGas does not currently have infrastructure in this specific area of the Montney.

The Corporation also expects there to be opportunities to increase volumes by tying-in new wells and building or purchasing adjoining facilities and systems to create larger processing infrastructure to capture operating synergies and enhance its competitive advantage. The strategic location of some of its existing gas processing infrastructure is expected to benefit from growing natural gas production in northeastern British Columbia and western Alberta, in response to the development of unconventional sources of gas, such as the Montney and Duvernay shale gas plays. The Townsend Facility, the Montney Facilities and their related infrastructure are examples of AltaGas' ability to capitalize on energy infrastructure growth opportunities. In October 2016, AltaGas reached a positive FID on the North Pine Facility, which will provide NGL processing capacity to producers in the area once it is in service. The North Pine Facility is well connected by rail to Canada's west coast including the Ridley Island Propane Export Terminal, which reached positive FID in January 2017. Through the Townsend Facility, the North Pine Facility and the Ridley Island Propane Export Terminal currently under construction, and the Montney Facilities currently under development, AltaGas is well positioned to provide a fully integrated midstream service offering while also providing access to higher netback markets for producer NGL. The Gordondale Gas Plant and the Blair Creek Facility are also meeting liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. Overall, the diverse nature of AltaGas' natural gas and NGL infrastructure is expected to provide ongoing opportunities for AltaGas to increase throughput, utilization and profitability.

Due to the integrated nature of AltaGas' gas gathering and processing assets, transmission services are often offered in combination with gathering and processing, natural gas marketing and extraction services. AltaGas is uniquely positioned to work with producers providing services across the integrated value chain, from wellhead to the coast and on to export markets. This is particularly the case with producers in the vast Montney and Duvernay basins under development in northeastern British Columbia and western Alberta. With the Ridley Island Propane Export Terminal near Prince Rupert, British Columbia currently under construction and the Petrogas Ferndale Terminal in the State of Washington, AltaGas can provide multiple outlets for producers to deliver their products to the highest value markets, including Asia. AltaGas also pursues additional opportunities to enhance the value of its infrastructure through services ancillary to its infrastructure based businesses. These include maintaining the cost effective flow of gas through extraction plants and increasing services provided to producers. AltaGas is also reviewing plant optimization opportunities which will generate another source of cash flow and improve customer netbacks. AltaGas has significant gas and power market knowledge, which it employs across all its assets to enhance returns along the energy value chain and more effectively serve customers' needs.

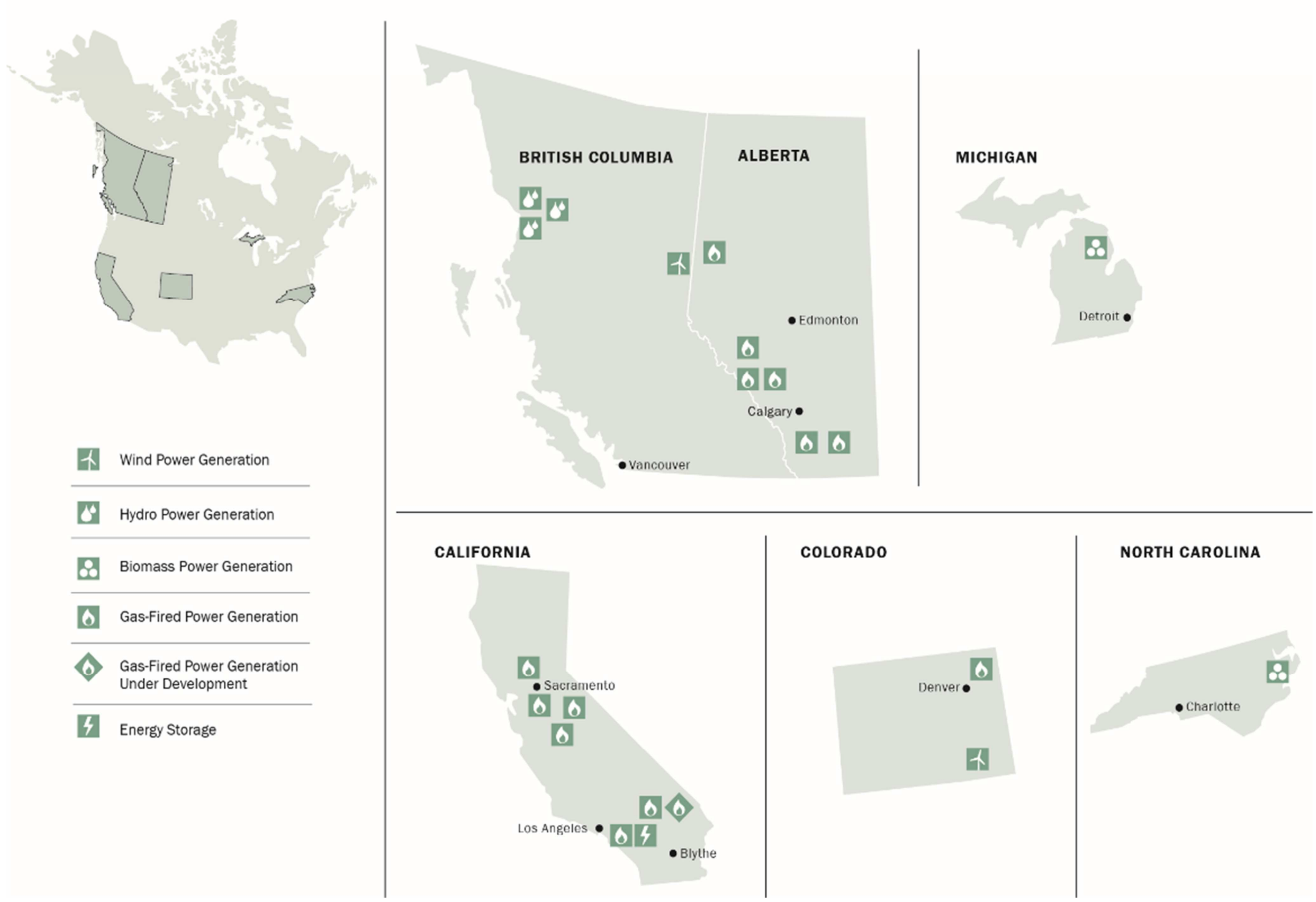
POWER

Description of Assets

AltaGas' Power segment is engaged in the generation and sale of electricity and ancillary services in Western Canada and the United States, all of which are under medium and long-term contracts with the exception of the Alberta assets, the 44 MW Pomona gas-fired plant, and the Craven facility, which is contracted until the end of 2017. AltaGas continues to expand its geographic footprint and to capitalize on the demand for clean energy sources, while increasing earnings, cash flow stability, and predictability.

As at December 31, 2016, the Power segment included 1,688 MW of gross power generation capacity from hydro, gas-fired, wind and biomass, 20 MW of energy storage capacity, along with an additional 1,253 MW of assets under development.

With the termination of the Sundance B PPAs, AltaGas' power portfolio in Alberta has been reduced to 65 MW, representing 4 percent of AltaGas' total generation capacity.



Specifically, the Power segment includes:

- Seven natural gas-fired plants with 1,194 MW of generating capacity in the United States, including the 523 MW San Joaquin Facilities, the 507 MW Blythe Energy Center, the 50 MW Ripon facility and the 44 MW Pomona facility, all of which are located in California, and the 70 MW Brush II facility in Colorado. All facilities are under PPAs with creditworthy utilities except the 44 MW Pomona facility, where the current gas-fired plant is under merchant status until it is repowered. A further 1,163 MW of gas-fired generation is under development;
- 277 MW of operating run-of-river generation in British Columbia (the Northwest Hydro Facilities), under 60-year Electricity Purchase Agreements (EPA) fully indexed to the Consumer Price Index (CPI) with BC Hydro;
- 117 MW of wind generation, of which 102 MW is in British Columbia and 15 MW is in Colorado. All operating wind generation is sold via long-term EPAs;
- 45 MW of cogeneration and 20 MW of gas-fired peaking plant capacity in Alberta, with a further 90 MW of peaking plant capacity under development;
- 35 MW of biomass generation in the United States. The Grayling facility is under a long-term PPA with a strong counterparty while the Craven facility is contracted through 2017; and
- 20 MW of lithium ion battery storage in Pomona, California, with a 10 year agreement for capacity under contract with SCE.

In northern California, the Corporation is focused on owning generating and energy storage assets in locally constrained areas near load pockets as local resource adequacy needs result in more opportunities for expansion, re-contracting and energy storage. On November 30, 2015, AltaGas acquired three northern California natural 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 Pacific Gas & Electric Company (PG&E) under PPAs which are structured as tolling arrangements for 100 percent of facility energy, capacity and ancillary services. This is in addition to Ripon acquired in early 2015, which is also contracted with PG&E until May 31, 2018.

In southern California, the existing 507 MW Blythe Energy Center is currently operating under a long-term PPA with SCE until July 31, 2020, serving the CAISO market. The opportunities for growth include Blythe Energy Center's unique position to potentially serve CAISO and the WAPA markets, as well as alternative configurations (gas, combined with solar and energy storage). Blythe Energy Center is located on an owned 76-acre site which provides a significant geographic footprint and water resource to support future expansions. The facility is directly connected to a Southern California Gas Company natural gas pipeline for its supply and is in the process of reactivating an El Paso Gas Company connection as a second potential supply source, and interconnects to SCE and CAISO via its 67-mile transmission line. The facility also has the capability of directly connecting to both the California and Arizona markets. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth. 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. Please refer to the *Growth Capital* section in this MD&A for more information on Pomona.

In addition to the plans for repowering at the Pomona site, AltaGas constructed, owns and operates a lithium-ion battery storage facility at the site. The Pomona Energy Storage Facility is a 20 MW (80MWh) facility which entered service in December of 2016 and is under contract for 20 MW of resource adequacy capacity with SCE under a 10-year ESA. AltaGas retains the rights to the energy and ancillary service attributes of the facility which will be sold on a merchant basis into the CAISO.

AltaGas owns and operates the Northwest Hydro Facilities in northwest British Columbia with total generation capacity of 277 MW. The three facilities include Forrest Kerr, Volcano, and McLymont. McLymont commenced commercial operations in the fourth quarter of 2015. These facilities are each underpinned by 60-year EPAs, fully indexed to CPI. Impact Benefit Agreements are in place for all three facilities, ensuring a cooperative and mutually beneficial relationship between the Tahltan Nation and AltaGas.

AltaGas also owns the 102 MW Bear Mountain Wind Park (Bear Mountain) in British Columbia, which came into service in October 2009 and has a 25-year EPA with BC Hydro, and a 50 percent interest in the Busch Ranch wind farm (Busch Ranch), a 29 MW wind farm in Colorado with a 25-year EPA with the local utility, which came into service in October 2012. AltaGas' biomass assets include a 30 percent working interest in a 37 MW wood biomass power facility in Grayling, Michigan and a 50 percent working interest in a 48 MW wood biomass power facility in Craven County, North Carolina. The Grayling facility is contracted under a long term PPA with CMS Energy and the Craven facility is contracted through 2017 with Duke Energy. AltaGas and its working interest partners in Craven believe the dispatchable renewable energy plant and the community it serves provide both an economic and environmentally compelling case for a potential PPA renewal following the expiry of the current PPA.

AltaGas also sells power to Commercial and Industrial (C&I) end-users in Alberta. Counterparties are subject to credit reviews and credit thresholds in the normal course of business. AltaGas actively markets electricity and gas directly to end-users, enabling the Corporation to secure fixed-price sales at competitive market prices while earning fees associated with the administration of the metered data and billing. These C&I sales are typically for three to five year terms. A portion of the electricity sales are used to secure long-term power sales for AltaGas' Alberta generation portfolio, offering AltaGas price certainty.

Capitalize on Opportunities

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

- Capitalize on North American demand for clean energy;
- Maintain strong relationships with local communities, First Nations, governments, and regulatory bodies;
- Further grow and diversify the power generation portfolio by geography and fuel source;

- Acquire and develop power infrastructure backstopped by long-term PPAs or supported by strong power supply and demand fundamentals;
- Secure PPAs for Blythe II and ultimately Blythe III (the 76-acres of land for development north of the current Blythe Energy Center), as well as seeking to re-contract and/or extend existing PPAs for operating assets on beneficial terms; and
- Explore opportunities for new natural gas-fired and renewable power generation in Alberta.

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

The demand for clean energy continues to be strong across North America as the industry addresses climate change legislation and utilities are faced with RPS. Per the U.S. Energy Information Administration, coal and natural gas were equal as the largest fuel source for power generation in the United States in 2015. Utilities' reliance on coal is lessening as its market share continues to decrease for environmental and economic reasons as low cost natural gas and increasing renewables provide a cost competitive option to coal as a source of fuel on a marginal cost basis in many parts of North America. The economic benefit of natural gas-fired generation is enhanced by capital cost efficiency, dispatch flexibility and the fact that it is a cleaner burning fuel, thus enhancing its appeal as a source of energy.

Opportunities to develop and own additional power generation are likely to arise with the growing North American demand for cleaner energy sources such as natural gas, solar, wind, and hydro. AltaGas has significant opportunities to expand its generating assets in California and across the United States, as well as the potential opportunity to develop new gas-fired and renewable generation in Alberta as the GOA moves forward with phasing out coal-fired electricity generation by 2030. In addition, the Once-Through Cooling Water Policy for power generating facility intake structures in California is expected to result in additional opportunities to develop clean power generation capacity. The San Joaquin Facilities, Blythe Energy Center, Bear Mountain, Busch Ranch, Grayling Generating Station, Craven County wood biomass power facility, the Northwest Hydro Facilities, Ripon, Pomona, Brush II and the Pomona Energy Storage Facility are all examples of AltaGas' strategy in action to meet North America's growing demand for clean energy.

UTILITIES

Description of Assets

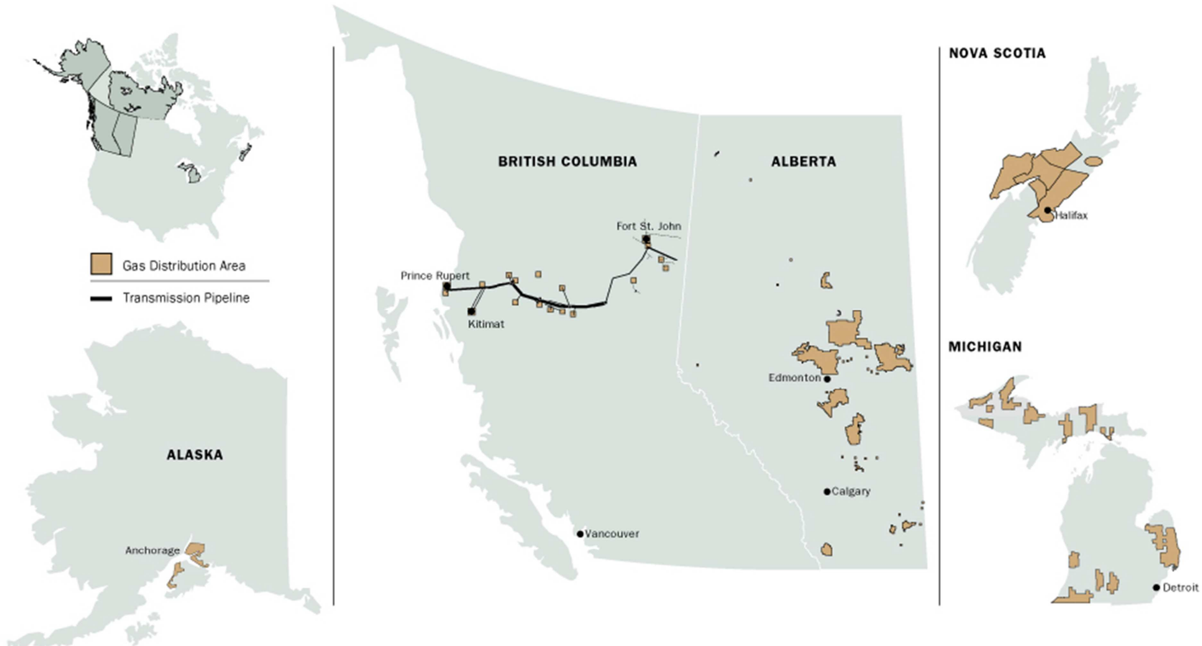
AltaGas owns and operates utility assets that store and deliver natural gas to end-users in Alberta, British Columbia, Nova Scotia, Michigan and Alaska. AltaGas also owns a one-third equity interest in the utility that delivers natural gas to end-users in Inuvik, Northwest Territories. AltaGas' utility businesses serve over 570,000 customers and have a rate base of approximately $1.9 billion.

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

The Utilities segment includes:

- SEMCO Gas in Michigan;
- ENSTAR in Alaska;
- 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC (CINGSA) in Alaska;
- AUI in Alberta;
- PNG in British Columbia;
- Heritage Gas in Nova Scotia; and

- One-third interest in Inuvik Gas Ltd. (Inuvik Gas) and the Ikhil Joint Venture in the Northwest Territories.



All of the utilities are allowed the opportunity to earn regulated returns. This return on rate base is composed of regulator-allowed financing costs and return on equity (ROE). In a cost-of-service regime and Performance Based Regulation (PBR) regime, if actual costs are different from those recoverable through approved rates, the utility bears the risk of this difference other than for certain costs that are subject to deferral treatment. Inuvik Gas operates a natural gas distribution franchise in a regulatory environment where delivery service and natural gas pricing are market-based.

Earnings in the Utilities segment are seasonal, as revenues are primarily based on the demand for space heating in the winter months, mainly from November to March. Costs, on the other hand, are generally incurred more uniformly over the year. This typically results in stronger first and fourth quarters and weaker second and third quarters. In Alberta, Nova Scotia, Michigan and Alaska, earnings can be impacted by variations from normal weather resulting in delivered volumes being different than anticipated. Increases in the number of customers or changes in customer usage are other factors that might typically affect delivered volumes, and hence actual earned returns for the Utilities segment. PNG is authorized by the BCUC to maintain a Revenue Stabilization Adjustment Mechanism regulatory account primarily to mitigate the effect of weather on earnings.

SEMCO Gas

SEMCO owns and operates a regulated natural gas distribution utility in Michigan under the name SEMCO Gas and has an interest in a regulated natural gas storage facility in Michigan. At the end of 2016, SEMCO Gas had approximately 300,000 customers. Of these customers, approximately 91 percent are residential. In 2016, SEMCO Gas experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favorable price of natural gas. The rate base at year end was approximately US$478 million. In 2016, the approved regulated ROE for SEMCO Gas was 10.35 percent with an approved capital structure based on 49 percent equity.

SEMCO Gas is regulated by the MPSC. It operates under cost-of-service regulation and utilizes actual results from the most recently completed fiscal year along with known and measurable changes in its application for new rates.

In December 2012, SEMCO Gas filed an application with the MPSC seeking to amend the MRP effective in 2013. SEMCO Gas proposed to double the amount spent annually on the MRP from US$4 million to US$9 million; to double the miles of main replaced from 13 miles to 26 miles per year; to include vintage plastic main as eligible main, and to increase the MRP surcharge to recover the incremental capital costs associated with the MRP. On May 29, 2013, the MPSC issued an order approving SEMCO Gas' application. Revised surcharges generating incremental revenue are effective for the period June 1, 2013 through May 30, 2017.

On January 23, 2015, SEMCO Gas filed an MRP rate case. As part of the case, SEMCO Gas requested to continue the MRP program for an additional five years. The anticipated annual average capital spending over the five year period is approximately US$10 million. In June 2015, the MPSC approved this filing and the new rates became effective immediately following the approval.

In May 2015, SEMCO Gas filed its 2014 Energy Optimization (EO) reconciliation with the MPSC. As part of the filing, SEMCO Gas demonstrated that it had implemented its EO plan during 2014, and met the goals and objectives for the approved performance incentive. In September 2015, the MPSC issued an order authorizing SEMCO Gas to collect US$1 million as its 2014 EO plan performance incentive.

In April 2016, SEMCO Gas filed its 2015 EO reconciliation with the MPSC. As part of the filing, SEMCO Gas demonstrated that it had implemented its EO plan during 2015, and met the goals and objectives for the approved performance incentive. In July 2016, the MPSC issued an order authorizing SEMCO Gas to collect US$1 million as its 2015 EO plan performance incentive.

In December 2016, SEMCO Gas filed an application with the MPSC seeking approval to construct, own, and operate the MCP. Please refer to the *Growth Capital* section of this MD&A for further information.

<u>ENSTAR and CINGSA</u>

SEMCO owns and operates a regulated natural gas distribution utility in Alaska under the name ENSTAR. SEMCO, through a subsidiary, holds a 65 percent interest in CINGSA, a regulated natural gas storage utility in Alaska. At the end of 2016, ENSTAR had approximately 143,000 customers including residential, commercial and transportation and of these customers, approximately 91 percent are residential. In 2016, ENSTAR experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favorable price of natural gas. The rate base at year end was approximately US$279 million for ENSTAR and US$83 million for CINGSA (SEMCO's 65 percent share).

ENSTAR and CINGSA are regulated by the RCA and operate under cost-of-service regulation utilizing actual results from the most recently completed fiscal year along with known and measureable changes in their application for new rates.

Effective October 1, 2015, the RCA allowed a permanent rate increase of approximately 2.2 percent over the interim and refundable rates that went into effect on November 1, 2014. Furthermore, 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. In addition, effective January 1, 2016, the RCA granted another interim and refundable rate increase of approximately 0.8 percent pending resolution of the 2016 rate case. In June 2016, ENSTAR filed the 2016 rate case and in July 2016, the RCA approved ENSTAR's request for an additional 1.6 percent interim and refundable rate increase on total revenues, or approximately US$5 million (annualized), effective August 1, 2016. ENSTAR is requesting an overall annual base rate increase of approximately $12 million, or 3.9 percent on total revenues. ENSTAR expects the rate case to be adjudicated in the third quarter of 2017.

CINGSA made a filing in March 2014, updating the rates for service for the CINGSA Storage Facility to reflect its actual capital investment, permanent debt cost, and actual operating costs. In May 2014, the regulators approved CINGSA's new rates on a permanent basis to be effective for billings on or after May 12, 2014. CINGSA is also required to file a base rate case in mid-2017 based upon data from a test year ending December 31, 2016.

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.

AltaGas Utilities Inc.

AUI owns and operates a regulated natural gas distribution utility in Alberta. At the end of 2016, AUI served approximately 79,000 customers. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. Customer growth in 2016 was 1 percent and AUI's rate base at year end was approximately $299 million. For 2013-2016, the Alberta Utilities Commission (AUC) approved an ROE of 8.3 percent on 41 percent equity. For 2017, the AUC approved an ROE of 8.5 percent on 41 percent equity.

AUI is currently operating under a revenue cap per customer formula under PBR. The first generation PBR plan was implemented for all Alberta electric and natural gas distribution companies, and was effective for AUI as of January 1, 2013. The first generation PBR term is from 2013-2017. The PBR framework is intended to incentivize utilities to be more efficient. Although formulaic, the PBR mechanism allows for recovery of costs related to exogenous events and major capital replacements. Rates are adjusted annually based on an inflation factor less expected productivity. Under a revenue cap formula, an adjustment is also made based on growth in customer numbers.

With the imminent expiry of the first generation PBR plan that established 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 (2018-2022).

Pacific Northern Gas Ltd.

PNG operates a transmission and distribution system in the west central portion of northern British Columbia (PNG West) and in the areas of Fort St. John and Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) in northeastern British Columbia (PNG(N.E.)). At the end of 2016, PNG served approximately 42,000 customers. Customer growth in 2016 was 1 percent. Approximately 87 percent of PNG's total customers are residential. PNG's rate base at year end was approximately $204 million. On August 10, 2016, the BCUC issued a decision confirming no changes to the benchmark utility's common equity ratio and allowed ROE. As such, the allowed ROE of 9.50 percent for PNG West and PNG(N.E.) TR, and 9.25 percent for PNG(N.E.) FSJ/DC remained unchanged from 2015. The approved common equity ratio for PNG West and PNG(N.E.) TR division also remains at 46.5 percent and remains at 41 percent for PNG(N.E.) FSJ/DC division.

PNG operates under a cost of service regulatory model whereby customer rates are set based on revenues that allow for the recovery of forecast costs plus an established rate of return on deemed common equity of PNG.

The BCUC approved PNG's 2016-2017 Revenue Requirements Application and determined final customer delivery rates for 2016 and 2017. PNG also submitted a Fourth Quarter Gas Report for commodity rate increases and an increase in the Revenue Stabilization Adjustment Mechanism (RSAM) rate riders for core customers due to warmer weather experienced during 2016. These changes, which were approved by the BCUC, combined with previously approved delivery rate increases for 2017, will result in customer rate increases ranging from 1 to 25 percent effective January 1, 2017.

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 expansion (the PNG Pipeline Looping Project). These TRAs provide for cost recovery of development expenses incurred with respect to the PNG Pipeline Looping 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 of the terms of its TRA with PNG and, as part of the amendment, also paid back its share of the project development expenses and recoveries of overhead costs to date.

Heritage Gas Limited

Heritage Gas has the exclusive rights to distribute natural gas through its distribution system to all or part of seven counties in Nova Scotia, including the Halifax Regional Municipality. In 2016, Heritage Gas' customer base grew by 3 percent and ended the year at approximately 6,500 customers. Heritage Gas has a mix of residential, small commercial and large commercial customers. Heritage Gas' rate base at year end was approximately $288 million. For 2016 and 2015, Heritage Gas' approved regulated ROE was 11 percent with a prescribed capital structure of 45 percent equity and 55 percent debt.

Heritage Gas operates under cost-of-service regulation and is regulated by the NSUARB. In order to maintain competitive pricing and customer retention, 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 their previously approved distribution rates while the Customer Retention Program is in place. Heritage Gas also requested 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 during 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 estimates that the Customer Retention Program will be in place through to 2021.

Inuvik Gas Ltd. & Ikhil Joint Venture

AltaGas has a one-third equity interest in Inuvik Gas and the Ikhil Joint Venture (Ikhil) natural gas reserves, which have historically supplied Inuvik Gas with natural gas for the Town of Inuvik. The Ikhil 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 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.

Capitalize on Opportunities

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

- Maximize use of existing infrastructure and market penetration in order to maintain cost-effective rates;
- Invest in the safety and reliability of existing infrastructure, including delivery system upgrade programs;
- Expand infrastructure to new markets to bring the economic and environmental benefits of gas to new customers, without unduly burdening existing customers;
- Maintain strong relationships with local communities, First Nations groups, governments, and regulatory bodies;
- Maintain strong community and regulatory relationships while ensuring fair returns to shareholders; and
- Acquire new franchises when the opportunities arise.

AltaGas expects to grow its existing utility infrastructure through continued investment and capital improvements in franchise areas, which will result in rate base growth and continued customer growth including the conversion of users of alternative energy sources to natural gas. After adjusting for the impact of foreign exchange translation, AltaGas' utilities have averaged 6 percent rate base growth over the past three years. The growth in rate base is a direct result of prudent investments in current areas of operations, as well as the addition of new customers. The growth rate of new customers varies amongst the Corporation's utilities with mature utilities seeing more moderate growth rates, which are generally tied closely to the economic growth of the respective franchise regions.

CONSOLIDATED FINANCIAL REVIEW

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2016**	2015	**2016**	2015
Revenue	**661**	580	**2,190**	2,193
Normalized EBITDA(1)	**194**	173	**701**	582
Net income (loss) applicable to common shares	**38**	(54)	**155**	10
Normalized net income(1)	**48**	56	**153**	140
Total assets	**10,201**	10,100	**10,201**	10,100
Total long-term liabilities	**4,589**	4,949	**4,589**	4,949
Net additions to property, plant and equipment	**121**	732	**405**	1,150
Dividends declared(2)	**87**	72	**320**	260
Normalized funds from operations(1)	**172**	159	**554**	470

	Three Months Ended December 31		Year Ended December 31	
($ per share, except shares outstanding)	**2016**	2015	**2016**	2015
Net income (loss) per common share - basic	**0.23**	(0.37)	**0.99**	0.07
Net income (loss) per common share - diluted	**0.23**	(0.37)	**0.99**	0.07
Normalized net income - basic(1)	**0.29**	0.38	**0.98**	1.02
Dividends declared(2)	**0.53**	0.50	**2.03**	1.89
Normalized funds from operations(1)	**1.04**	1.09	**3.52**	3.41
Shares outstanding - basic (millions)				
During the period(3)	**166**	146	**157**	138
End of period	**167**	146	**167**	146

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

(2) Dividends declared per common share per month $0.1475 beginning on May 26, 2014, $0.16 beginning on May 26, 2015, $0.165 beginning on October 26, 2015, and $0.175 beginning on August 25, 2016.

(3) Weighted average.

Three Months Ended December 31

Normalized EBITDA for the fourth quarter of 2016 was $194 million, compared to $173 million in 2015. The increase was mainly due to a full quarter contribution from the San Joaquin Facilities, commencement of commercial operations at the Townsend Facility in the third quarter of 2016, the absence of equity losses from the Sundance B PPAs, colder weather experienced at all Utilities, higher earnings from Petrogas including the dividend income from the Petrogas Preferred Shares, and the interim refundable rate increases at ENSTAR. These increases were partially offset by lower contributions from the Northwest Hydro Facilities due to unfavorable weather conditions leading to lower river flows, lower gains from frac hedges, higher incentive compensation expense as a result of the Corporation achieving key strategic objectives for 2016, the impact of the Tidewater Gas Asset Disposition, and lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels.

Normalized funds from operations for the fourth quarter of 2016 were $172 million ($1.04 per share), compared to $159 million ($1.09 per share) for the same quarter in 2015, reflecting the same drivers as normalized EBITDA as well as lower current income tax expense, partially offset by higher interest expense and lower common share dividends from Petrogas. In the fourth quarter of 2016, AltaGas received $6 million in common share dividends from Petrogas compared to $11 million received in the fourth quarter of 2015. In 2016, Petrogas common share dividends were paid quarterly, whereas in 2015, common share dividends were only declared in the fourth quarter.

Operating and administrative expenses for the fourth quarter of 2016 were $131 million, compared to $120 million for the same quarter in 2015. The increase was mainly due to the Sundance B PPAs termination costs and higher employee incentive compensation expense. Depreciation and amortization expense for the fourth quarter of 2016 was $70 million, compared to $59 million for the same quarter in 2015. The increase was mainly due to new assets placed into service or acquired. Interest expense for the fourth quarter of 2016 was $40 million, compared to $34 million for the same quarter in 2015. The increase was mainly due to higher average debt outstanding, lower capitalized interest, and higher average interest rates.

In December 2016, AltaGas Pipeline Partnership and the GOA reached a definitive settlement agreement regarding the termination of the Sundance B PPAs previously held by ASTC. Under the settlement agreement, AltaGas agreed to contribute 391,879 self-generated carbon offsets and to make total cash payments in the aggregate of $6 million payable in equal annual installments over three years starting in 2018. AltaGas Pipeline Partnership and ASTC were also granted a full release from all past, present and future obligations respecting the Sundance B PPAs by the GOA. As a result of the settlement agreement, AltaGas recorded a pre-tax termination expense of $8 million (after-tax $7 million) in the fourth quarter of 2016. Prior to the settlement with the GOA, ASTC was dissolved, and as a result, AltaGas recorded a tax recovery of $8 million in the fourth quarter of 2016. Including the tax recovery on the dissolution of ASTC, the after-tax impact of the settlement on AltaGas' consolidated earnings for the three months ended December 31, 2016 was nominal.

AltaGas recorded income tax expense of $6 million for the fourth quarter of 2016 compared to $3 million in the same quarter of 2015. The increase was mainly due to higher taxable earnings in the fourth quarter of 2016, including higher taxable earnings from U.S. operations which bear higher corporate income tax rates, partially offset by an $8 million tax recovery recorded on the dissolution of ASTC.

Net income applicable to common shares for the fourth quarter of 2016 was $38 million ($0.23 per share) compared to a net loss applicable to common shares of $54 million ($0.37 per share) for the same quarter in 2015. The increase in net income applicable to common shares in the fourth quarter of 2016 was mainly due to the $114 million of after-tax provisions taken on various assets and investments in the fourth quarter of 2015 and the same previously referenced factors resulting in the increase in normalized EBITDA in the fourth quarter of 2016, partially offset by the Sundance B PPAs termination costs, lower unrealized gains on risk management contracts, higher depreciation and amortization expense, interest expense and income tax expense.

Normalized net income was $48 million ($0.29 per share) for the fourth quarter of 2016, compared to $56 million ($0.38 per share) reported for the same quarter in 2015. The decrease was driven by higher depreciation and amortization expense, interest expense, income tax expense, partially offset by the same previously referenced factors resulting in the increase in normalized EBITDA in the fourth quarter of 2016. Normalizing items in the fourth quarter of 2016 included after-tax amounts related to transaction costs on acquisitions, unrealized losses on risk management contracts, losses on long-term investments, the Sundance B PPAs termination costs and the tax recovery on the dissolution of ASTC. In the fourth quarter of 2015, normalizing items included after-tax amounts related to transaction costs incurred on acquisitions, development costs related to energy exports, provisions on assets and on investments accounted for by the equity method, unrealized gains on risk management contracts, and losses on long-term investments.

Year Ended December 31

Normalized EBITDA for the year ended December 31, 2016 was $701 million, compared to $582 million for the same period in 2015. The increase was primarily due to a full year of EBITDA generated from the San Joaquin Facilities, commencement of commercial operations at the Townsend Facility, rate and customer growth at the Utilities, higher contributions from the Northwest Hydro Facilities resulting from a full year of contribution from McLymont, the impact of the stronger U.S. dollar on reported results of the U.S. assets, the absence of turnarounds at the Younger and Harmattan facilities, lower equity losses from the Sundance B PPAs, and higher earnings from Petrogas including the dividend income from the Petrogas Preferred Shares. These increases were partially offset by lower gains from frac hedges, the impact of warmer weather experienced at all of the Utilities during the first quarter of 2016, the impact from the Tidewater Gas Asset Disposition, lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels, higher incentive compensation expense as a result of the Corporation achieving key strategic objectives for 2016, and the impact from the expiration of the Pomona PPA at the end of 2015.

Normalized funds from operations for the year ended December 31, 2016 were $554 million ($3.52 per share), compared to $470 million ($3.41 per share) in 2015, driven by the same factors impacting normalized EBITDA as well as higher common share dividends from Petrogas, partially offset by higher interest expense. For the year ended December 31, 2016, AltaGas received $24 million in common share dividends from Petrogas compared to $11 million received in 2015.

Operating and administrative expenses for the year ended December 31, 2016 were $509 million, compared to $492 million in 2015. The increase was primarily due to higher operating and administrative costs incurred by the Power segment due to new assets placed into service or acquired, the impact of the stronger U.S. dollar, the Sundance B PPAs termination costs, and restructuring costs of approximately $7 million recorded in the second quarter of 2016 related to the Workforce Restructuring. This was partially offset by the decrease in operating and administrative expenses associated with the Tidewater Gas Asset Disposition. Depreciation and amortization expense for the year ended December 31, 2016 increased to $272 million, compared to $212 million in 2015 mainly due to new assets placed into service or acquired and the impact of the stronger U.S. dollar, partially offset by lower depreciation and amortization expense as a result of the Tidewater Gas Asset Disposition. Interest expense for the year ended December 31, 2016 was $151 million, compared to $125 million in 2015. The increase was mainly due to higher average debt outstanding and lower capitalized interest, partially offset by lower average interest rates.

In the first quarter of 2016, ASTC exercised its right to terminate the Sundance B PPAs effective March 8, 2016 pursuant to the change in law provision of the Sundance B PPAs as a result of recent changes in law regarding the Alberta Specified Gas Emitters Regulation and as a result, AltaGas recognized a pre-tax provision of $4 million on its investment in ASTC to settle the working capital deficiency in the first quarter of 2016. In addition, AltaGas recognized a pre-tax termination expense of $8 million (after-tax $7 million) upon reaching a definitive settlement agreement with the GOA regarding the termination of the Sundance B PPAs in the fourth quarter of 2016. Including the tax recovery on the dissolution of ASTC of $8 million, the after-tax impact on the termination of the Sundance B PPAs was approximately $3 million. As part of the settlement agreement, AltaGas Pipeline Partnership and ASTC were also granted a full release from all past, present and future obligations respecting the Sundance B PPAs by the GOA.

On February 29, 2016, 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 to Tidewater for $30 million of cash and approximately 43.7 million common shares of Tidewater. At the time of disposition, the volumes processed at these facilities totaled approximately 120 Mmcf/d. A pre-tax gain of $5 million was recognized on the sale for the year ended December 31, 2016.

During the third quarter of 2016, PNG recognized revenue of approximately $7 million related to the recovery of development costs from Triton LNG Limited Partnership for the PNG Pipeline Looping Project, a development project to expand the capacity of PNG's natural gas transmission line. Triton LNG Limited Partnership is a wholly-owned subsidiary of AltaGas Idemitsu Joint Venture Limited Partnership.

AltaGas recorded income tax expense of $33 million for the year ended December 31, 2016, compared to $48 million in 2015. Income tax expense decreased primarily due to the absence of the one-time, non-cash $14 million charge recorded in the second quarter of 2015 related to the increase in the Alberta corporate income tax rate, 2015 charges to income that did not attract tax recoveries, the $10 million tax recovery related to the Tidewater Gas Asset Disposition recorded in the first quarter of 2016 and the $8 million tax recovery related to the dissolution of ASTC in the fourth quarter of 2016. This was partially offset by higher taxable earnings in 2016 compared to 2015.

Net income applicable to common shares for the year ended December 31, 2016 was $155 million ($0.99 per share) compared to $10 million ($0.07 per share) for the same period in 2015. The increase in net income applicable to common shares for the year ended December 31, 2016 was mainly due to the $119 million of after-tax provisions taken on various assets and investments in 2015, lower income tax expense, and the same factors previously referenced resulting in the increase in normalized EBITDA in 2016, partially offset by the Sundance B PPAs termination costs, lower unrealized gains on risk management contracts, higher depreciation and amortization expense, interest expense and preferred share dividends.

Normalized net income for the year ended December 31, 2016 was $153 million ($0.98 per share), compared to $140 million ($1.02 per share) in 2015. The variance was driven by the same factors previously referenced impacting normalized EBITDA as well as higher depreciation and amortization expense, interest expense and preferred share dividends. For the year ended December 31, 2016, normalizing items included after-tax amounts related to unrealized losses on risk management contracts, transaction costs related to acquisitions, gains on sale of assets and related tax recovery, a dilution loss recognized on an investment accounted for by the equity method, provision on investments accounted for by the equity method, restructuring costs, development costs incurred for energy export projects, the Sundance B PPAs termination costs, the tax recovery on the dissolution of ASTC, and the recovery of development costs for the PNG Pipeline Looping Project. For the year ended December 31, 2015, normalizing items included after-tax amounts related to unrealized gains on risk management contracts, loss on long-term investments, provisions on assets and investments accounted for by the equity method, development costs incurred for energy export projects, transaction costs related to acquisitions, and a statutory tax rate change.

Although normalized net income for the year ended December 31, 2016 increased by $13 million compared to 2015, normalized net income per share for the year ended December 31, 2016 decreased by $0.04 per share compared to 2015 as a result of a higher number of common shares outstanding in 2016.

NON-GAAP FINANCIAL MEASURES

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

References to normalized EBITDA, normalized net income and normalized funds from operations throughout this MD&A have the meanings as set out in this section.

Normalized EBITDA

($ millions)	Three Months Ended December 31 2016	Three Months Ended December 31 2015	Year Ended December 31 2016	Year Ended December 31 2015
Normalized EBITDA	**$ 194**	$ 173	**$ 701**	$ 582
Add (deduct):				
Transaction costs related to acquisitions	**(2)**	(2)	**(3)**	(2)
Unrealized gains (losses) on risk management contracts	**(12)**	8	**(11)**	9
Losses on long-term investments	**(1)**	(35)	**—**	(34)
Gains on sale of assets	**—**	—	**4**	—
Provisions on long-lived assets	**—**	(43)	**—**	(54)
Dilution loss on investment accounted for by the equity method	**—**	—	**(1)**	—
Provisions on investments accounted for by the equity method	**—**	(47)	**(5)**	(47)
Energy export development costs	**—**	(2)	**(1)**	(4)
Restructuring costs	**—**	—	**(7)**	—
Accretion expenses	**(3)**	(3)	**(11)**	(11)
Sundance B PPAs termination costs	**(8)**	—	**(8)**	—
Foreign exchange gains	**—**	6	**4**	6
Recovery of pipeline looping project development costs at PNG	**—**	—	**7**	—
EBITDA	**$ 168**	$ 55	**$ 669**	$ 445
Add (deduct):				
Depreciation and amortization	**(70)**	(59)	**(272)**	(212)
Interest expense	**(40)**	(34)	**(151)**	(125)
Income tax expense	**(6)**	(3)	**(33)**	(48)
Net income (loss) after taxes (GAAP financial measure)	**$ 52**	$ (41)	**$ 213**	$ 60

EBITDA is a measure of AltaGas' operating profitability prior to how business activities are financed, assets are amortized, or earnings are taxed. EBITDA is calculated from the Consolidated Statement of Income using net income adjusted for pre-tax depreciation and amortization, interest expense, and income tax expense.

Normalized EBITDA includes additional adjustments for unrealized gains (losses) on risk management contracts, gains (losses) on long-term investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, accretion expenses, foreign exchange gains (losses), provisions on investments accounted for by the equity method, provisions on certain long-lived assets, restructuring costs, dilution loss on an investment accounted for by the equity method, the Sundance B PPAs termination costs, and the recovery of development costs for the PNG Pipeline Looping Project. Normalized EBITDA also includes an adjustment for certain non-capitalizable project development costs related to energy export projects. AltaGas presents normalized EBITDA as a supplemental measure. Normalized EBITDA is frequently used by analysts and investors in the evaluation of entities within the industry as it excludes items that can vary substantially between entities depending on the accounting policies chosen, the book value of assets and the capital structure.

Normalized Net Income

($ millions)	Three Months Ended December 31 2016	2015	Year Ended December 31 2016	2015
Normalized net income	**$ 48**	$ 56	**$ 153**	$ 140
Add (deduct) after-tax:				
Transaction costs related to acquisitions	**(1)**	(1)	**(2)**	(1)
Unrealized gains (losses) on risk management contracts	**(9)**	6	**(8)**	7
Losses on long-term investments	**(1)**	(34)	**—**	(33)
Gains on sale of assets	**—**	—	**15**	—
Provisions on long-lived assets	**—**	(33)	**—**	(39)
Dilution loss on investment accounted for by the equity method	**—**	—	**(1)**	—
Provisions on investments accounted for by the equity method	**—**	(47)	**(2)**	(47)
Energy export development costs	**—**	(1)	**(1)**	(3)
Restructuring costs	**—**	—	**(5)**	—
Sundance B PPAs termination costs	**(7)**	—	**(7)**	—
Tax recovery on dissolution of ASTC	**8**	—	**8**	—
Statutory tax rate change	**—**	—	**—**	(14)
Recovery of pipeline looping project development costs at PNG	**—**	—	**5**	—
Net income (loss) applicable to common shares (GAAP financial measure)	**$ 38**	$ (54)	**$ 155**	$ 10

Normalized net income represents net income applicable to common shares adjusted for the after-tax impact of unrealized gains (losses) on risk management contracts, gains (losses) on long-term investments, transaction costs related to acquisitions, gains (losses) on the sale of assets, provisions on investments accounted for by the equity method, provisions on certain long-lived assets, restructuring costs, dilution loss on investment accounted for by the equity method, the Sundance B PPAs termination costs, the tax recovery on the dissolution of ASTC, the recovery of development costs for the PNG Pipeline Looping Project, and statutory tax rate changes. Normalized net income also includes an adjustment for certain non-capitalizable project development costs related to energy export projects. This measure is presented in order to enhance the comparability of AltaGas' earnings, as it reflects the underlying performance of AltaGas' business activities.

Normalized Funds from Operations

($ millions)	Three Months Ended December 31 2016	2015	Year Ended December 31 2016	2015
Normalized funds from operations	**$ 172**	$ 159	**$ 554**	$ 470
Add (deduct):				
Energy export development costs	**—**	(1)	**—**	(1)
Transaction costs related to acquisitions	**(2)**	(2)	**(3)**	(2)
Restructuring costs	**—**	—	**(7)**	—
Current tax expense on disposition	**—**	(1)	**—**	(1)
Sundance B PPAs termination costs	**(11)**	—	**(11)**	—
Recovery of pipeline looping project development costs at PNG	**—**	—	**5**	—
Funds from operations	**159**	155	**538**	466
Add (deduct):				
Net change in operating assets and liabilities	**(21)**	(61)	**(78)**	39
Asset retirement obligations settled	**(2)**	(2)	**(4)**	(4)
Cash from operations (GAAP financial measure)	**$ 136**	$ 92	**$ 456**	$ 501

Normalized funds from operations is used to assist management and investors in analyzing the liquidity of the Corporation without regard to changes in operating assets and liabilities in the period and non-operating related expenses (net of current taxes) such as transaction costs related to acquisitions, the Sundance B PPAs termination costs, the recovery of development costs for the PNG Pipeline Looping Project, current tax expense on disposition, and restructuring costs.

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

Management uses this measure to understand the ability to generate funds for capital investments, debt repayment, dividend payments and other investing activities.

Funds from operations and normalized funds from operations as presented should not be viewed as an alternative to cash from operations or other cash flow measures calculated in accordance with GAAP.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized EBITDA [1]	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2016**	2015	**2016**	2015
Gas	**$ 49**	$ 44	**$ 163**	$ 172
Power	**63**	53	**285**	177
Utilities	**90**	80	**277**	257
Sub-total: Operating Segments	**202**	177	**725**	606
Corporate	**(8)**	(4)	**(24)**	(24)
	$ 194	$ 173	**$ 701**	$ 582

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

GAS

OPERATING STATISTICS

	Three Months Ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Extraction inlet gas processed (Mmcf/d)[1]	**972**	909	**918**	910
FG&P inlet gas processed (Mmcf/d)[1] [2]	**365**	389	**312**	392
Total inlet gas processed (Mmcf/d)[1] [2]	**1,337**	1,298	**1,230**	1,302
Extraction ethane volumes (Bbls/d)[1]	**32,233**	32,250	**30,211**	30,970
Extraction NGL volumes (Bbls/d)[1] [3]	**37,454**	33,215	**34,224**	31,308
Total extraction volumes (Bbls/d)[1] [4]	**69,687**	65,465	**64,435**	62,278
Frac spread - realized ($/Bbl)[1] [5]	**6.11**	15.55	**7.41**	18.03
Frac spread - average spot price ($/Bbl)[1] [6]	**8.40**	5.06	**8.27**	5.10

(1) Average for the period.

(2) FG&P inlet gas volumes processed at the facilities sold to Tidewater on February 29, 2016 were approximately 125 Mmcf/d for the three months ended December 31, 2015 and approximately 131 Mmcf/d for the year ended December 31, 2015.

(3) NGL volumes refer to propane, butane and condensate.

(4) Includes Harmattan NGL processed on behalf of customers.

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

(6) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, before accounting for hedges, divided by the respective frac exposed volumes for the period.

Inlet gas volumes processed at the extraction facilities for the three months ended December 31, 2016 increased by 63 Mmcf/d, compared to the same period in 2015. The increase was due to higher processed volumes at EEEP as a result of increased ownership, partially offset by lower volumes at Harmattan. Inlet gas volumes processed at the field gathering and processing (FG&P) facilities for the three months ended December 31, 2016 decreased by 24 Mmcf/d primarily due to the Tidewater Gas Asset Disposition and lower volumes at the Gordondale facility, partially offset by volumes received at the newly constructed Townsend Facility.

Inlet gas volumes processed at the extraction facilities for the year ended December 31, 2016 increased by 8 Mmcf/d, compared to the same period in 2015. The increase was due to higher volumes at the Younger and Harmattan facilities in 2016 primarily due to major turnarounds in the prior year, partially offset by temporary plant shut-ins at EEEP and the Joffre Ethane Extraction

Plant (JEEP) as low commodity prices made extraction of certain NGL at these facilities uneconomical in the first half of 2016 and the shut-in of the non-operated Empress Gas Liquids Joint Venture (EGLJV) plant. Inlet gas volumes processed at the FG&P facilities for the year ended December 31, 2016 decreased by 80 Mmcf/d mainly due to the Tidewater Gas Asset Disposition and lower volumes at the Gordondale facility, partially offset by volumes received at the newly constructed Townsend Facility.

Average ethane volumes for the three months ended December 31, 2016 were relatively flat compared to the same period in 2015 due to lower Younger recoveries being largely offset by increased volumes at EEEP due to increased ownership. NGL volumes for the three months ended December 31, 2016 increased by 4,239 Bbls/d compared to the same period in 2015 due to higher produced volumes at EEEP due to increased ownership and higher production at Younger due to higher gas inlet and recoveries.

Average ethane volumes for the year ended December 31, 2016 decreased by 759 Bbls/d, while average NGL volumes increased by 2,916 Bbls/d, compared to the same period in 2015. Lower ethane volumes were due to temporary plant shut-ins at JEEP and EEEP in the first half of 2016, and lower volumes at the Younger facility, partially offset by higher volumes at the Harmattan facility due primarily to the turnaround in the prior year. Higher NGL volumes were due to higher recoveries, as well as a turnaround in the prior year at the Younger facility and higher volumes at EEEP due to increased ownership.

Three Months Ended December 31

The Gas segment reported normalized EBITDA of $49 million in the fourth quarter of 2016, compared to $44 million for the same quarter in 2015. In the fourth quarter of 2016, normalized EBITDA increased due to revenues from the Townsend Facility commencing operations in the third quarter of 2016, higher Petrogas earnings, partially offset by lower realized frac spreads as a result of hedging gains in 2015, the impact of the Tidewater Gas Asset Disposition, and lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels. AltaGas recorded equity earnings of $5 million from Petrogas, compared to $nil in the same quarter of 2015. The increase in Petrogas earnings was due to dividend income earned by AltaGas from the investment in Petrogas Preferred Shares in June 2016 and improved results from all of Petrogas' business lines. In the fourth quarter of 2016 Petrogas' earnings were benefitted by generally improved conditions from the Petrogas segments which support upstream activities, higher domestic NGL deliveries and continuing export shipments out of the Ferndale Terminal.

During the fourth quarter of 2016, AltaGas hedged 3,100 Bbls/d of NGL at an average frac spread of $11/Bbl, inclusive of basis differentials. During the fourth quarter of 2015, AltaGas hedged approximately 3,000 Bbls/d of NGL at an average frac spread of $27/Bbl, inclusive of basis differentials. The average indicative spot NGL frac spread for the fourth quarter of 2016 was approximately $8/Bbl compared to $5/Bbl in the same quarter of 2015. The realized frac spread of $6/Bbl (2015 - $16/Bbl) in the fourth quarter of 2016 was lower than the same quarter in 2015 due to realized gains on NGL frac hedges in the fourth quarter of 2015.

Year Ended December 31

The Gas segment reported normalized EBITDA of $163 million for the year ended December 31, 2016, compared to $172 million in 2015. The decrease in normalized EBITDA was due to realized hedging gains on 2015 frac hedges, the impact of the Tidewater Gas Asset Disposition, and lower incremental fee-for-service revenue at the Gordondale facility due to lower volumes delivered in excess of take-or-pay levels, partially offset by the addition of the Townsend Facility, the completion of major turnarounds at the Younger and Harmattan facilities during the second quarter of 2015 and higher Petrogas earnings.

For the year ended December 31, 2016, AltaGas recorded equity earnings of $12 million from Petrogas as compared to $7 million in 2015. The increase in Petrogas earnings was due to dividend income earned by AltaGas from the investment in Petrogas Preferred Shares in June 2016, increased volumes at the Ferndale Terminal and generally improved conditions at Petrogas' other terminals. These increases to equity earnings from Petrogas were partially offset by weaker results in the first half of 2016 from the Petrogas' segments which support upstream activities and weaker LPG export market pricing in the summer of 2016.

For the year ended December 31, 2016, AltaGas hedged 1,100 Bbls/d of NGL at an average frac spread of $14/Bbl, inclusive of basis differentials. For the year ended December 31, 2015, AltaGas hedged approximately 3,100 Bbls/d of NGL volumes at an average frac spread of $27/Bbl, inclusive of basis differentials. The average indicative spot NGL frac spread for the year ended December 31, 2016 was approximately $8/Bbl compared to $5/Bbl in 2015. Realized frac spread of $7/Bbl in 2016 (2015 - $18/Bbl) was lower than 2015 due to realized gains on NGL frac hedges in the 2015.

As a result of the Tidewater Gas Asset Disposition, AltaGas recognized a pre-tax gain of $5 million (after-tax gain of $15 million) for the year ended December 31, 2016.

No provisions on assets or equity investments were recorded for the year ended December 31, 2016 for the Gas segment. For the year ended December 31, 2015, AltaGas recorded a pre-tax provision of $17 million on its investment in its joint ventures with Idemitsu including in relation to the DC LNG Project; a pre-tax provision of $16 million on the gas processing assets that were held for sale to Tidewater as at December 31, 2015; and a pre-tax provision of $7 million on the DC LNG Project related to deferred lease expense.

POWER

OPERATING STATISTICS

	Three Months Ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Renewable power sold (GWh)	**196**	310	**1,551**	1,300
Conventional power sold (GWh)	**374**	1,264	**1,950**	4,408
Renewable capacity factor (%)	**18.8**	30.2	**39.1**	35.4
Contracted conventional equivalent availability factor (%) [1]	**99.8**	99.1	**97.3**	96.9

(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.

During the fourth quarter of 2016, the volume of renewable power sold decreased by 114 GWh and the volume of conventional power sold decreased by 890 GWh, compared to the same quarter in 2015. The decrease in renewable volumes was due to weather conditions with low temperatures and light precipitation contributing to an earlier end to seasonally higher river flows at the Northwest Hydro Facilities, and lower winds at the Bear Mountain wind facility. The decrease in conventional volumes sold is due to the termination of the Sundance B PPAs effective March 8, 2016 and lower dispatch at Blythe.

For the year ended December 31, 2016, the volume of renewable power sold increased by 251 GWh and the volume of conventional power sold decreased by 2,458 GWh compared to 2015. The increase in renewable volumes sold was due to a full year of McLymont being in-service. The decrease in conventional volumes sold was due to impact of the termination of the Sundance B PPAs effective March 8, 2016, lower dispatch at Blythe, and the expiration of the Pomona PPA, partially offset by a full year of volumes provided by the San Joaquin Facilities. Blythe earns fixed capacity payments under its PPA with SCE, and as a result, volumes of power sold at Blythe have a minimal impact on EBITDA.

The contracted conventional equivalent availability factor was higher for the three months and year ended December 31, 2016 as a result of the acquisition of the San Joaquin Facilities in November 2015, which have been running well with no operational issues.

The renewable capacity factor during the fourth quarter of 2016 was lower due to the decrease in volumes at the Northwest Hydro Facilities as noted above and the lower winds at Bear Mountain wind facility. The renewable capacity factor for the year ended December 31, 2016 was higher due to a full year of McLymont being in-service and higher overall river flows at the Northwest Hydro Facilities in the second quarter of 2016.

Three Months Ended December 31

The Power segment reported normalized EBITDA of $63 million in the fourth quarter of 2016, compared to $53 million in the same quarter of 2015. Normalized EBITDA increased as a result of the acquisition of the San Joaquin Facilities at the end of November 2015, and the absence of equity losses from the Sundance B PPAs. These increases were partially offset by the impact of lower river flows at the Northwest Hydro Facilities.

Year Ended December 31

The Power segment reported normalized EBITDA of $285 million for the year ended December 31, 2016, compared to $177 million in 2015. Normalized EBITDA increased as compared to the same period in 2015 as a result of the impact of the acquisition of the San Joaquin Facilities in November 2015, a full year of McLymont being in-service, the stronger U.S. dollar, and lower equity losses from the Sundance B PPAs. These increases were partially offset by the expiration of the Pomona PPA at the end of 2015, and higher operating and administrative costs due to new assets placed into service or acquired.

In the first quarter of 2016, ASTC exercised its right to terminate the Sundance B PPAs effective March 8, 2016 pursuant to the change in law provision of the Sundance B PPAs and as a result, AltaGas recognized a pre-tax provision of $4 million on its investment in ASTC to settle the working capital deficiency. On December 16, 2016, AltaGas Pipeline Partnership and the GOA reached a definitive settlement agreement regarding the termination of the Sundance B PPAs. Under the settlement agreement, AltaGas has agreed to contribute 391,879 self-generated carbon offsets and to make total cash payments in the aggregate of $6 million payable in equal installments over three years starting in 2018. As a result of the settlement agreement, AltaGas recorded a pre-tax termination expense of $8 million (after-tax $7 million) in the fourth quarter of 2016. Prior to the settlement with the GOA, ASTC was dissolved, and as a result, AltaGas recorded a tax recovery of $8 million in the fourth quarter of 2016. Including the tax recovery on the dissolution of ASTC of $8 million, the after-tax impact on the termination of the Sundance B PPAs was approximately $3 million.

Other than the pre-tax provision of $4 million recorded on the investment in ASTC in the first quarter of 2016, no further provisions on assets or equity investments were recorded for the year ended December 31, 2016 in the Power segment. For the year ended December 31, 2015, the Power segment recorded $43 million of pre-tax provisions, comprised of $26 million for AltaGas' investment in ASTC, as well as $17 million for certain wind development projects.

UTILITIES

OPERATING STATISTICS

	Three Months Ended December 31		Year Ended December 31	
	2016	2015	**2016**	2015
Canadian utilities				
Natural gas deliveries - end-use (PJ)[1]	**10.8**	10.2	**30.0**	31.8
Natural gas deliveries - transportation (PJ)[1]	**1.5**	1.9	**5.9**	6.9
U.S. utilities				
Natural gas deliveries - end-use (Bcf)[1]	**22.8**	20.2	**65.3**	68.3
Natural gas deliveries - transportation (Bcf)[1]	**14.2**	13.5	**51.5**	47.7
Service sites [2]	**574,875**	568,751	**574,875**	568,751
Degree day variance from normal - AUI (%) [3]	**(0.6)**	(10.0)	**(12.6)**	(10.0)
Degree day variance from normal - Heritage Gas (%) [3]	**(1.0)**	(8.0)	**(3.2)**	5.6
Degree day variance from normal - SEMCO Gas (%) [4]	**(6.1)**	(20.4)	**(6.9)**	—
Degree day variance from normal - ENSTAR (%) [4]	**(1.4)**	(6.1)	**(16.3)**	(9.0)

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

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

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

(4) A degree day for U.S. utilities is a measure of coldness determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Gas and during the prior 10 years for ENSTAR.

REGULATORY METRICS

Year Ended December 31	**2016**	2015
Approved ROE (%)		
Canadian utilities (average)	**9.7**	9.4
U.S. utilities (average)	**11.8**	11.8
Approved return on debt (%)		
Canadian utilities (average)	**5.0**	5.1
U.S. utilities (average)	**6.0**	6.0
Rate base *($ millions)*[1]		
Canadian utilities	**790**	741
U.S. utilities[2][3]	**840**	851

(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 AltaGas' 65 percent interest in Cook Inlet Natural Gas Storage Alaska LLC.

Three Months Ended December 31

The Utilities segment reported normalized EBITDA of $90 million in the fourth quarter of 2016, compared to $80 million in the same quarter of 2015. The increase was mainly due to colder weather experienced at all Utilities, interim and refundable rate increases at ENSTAR, and lower operating and administrative expenses.

Year Ended December 31

The Utilities segment reported normalized EBITDA of $277 million for the year ended December 31, 2016, compared to $257 million in 2015. The increase was mainly due to the impact of rate and customer growth, the stronger U.S. dollar, and a full-year of SEMCO Gas' MRP. These variances were partially offset by warmer weather experienced at all Utilities and the impact of the approved Customer Retention Program at Heritage Gas.

For the year ended December 31, 2016, PNG recognized revenue of approximately $7 million related to the PNG Pipeline Looping Project, which was normalized for in the determination of normalized EBITDA, normalized net income and normalized funds from operations.

On June 3, 2015, SEMCO Gas' MRP case was approved by the MPSC. This program is for the recovery of capital expenses projected from 2016 to 2020 combined with a reconciliation of the program that expired in December 2015. The new rates took effect in June 2015, resulting in approximately US$6 million of additional net revenue for the year ended December 31, 2016 (2015 – US$4 million).

No provisions on assets or equity investments were recorded for the year ended December 31, 2016 in the Utilities segment. For the year ended December 31, 2015, the Utilities segment recorded $4 million of pre-tax provisions related to AltaGas' one-third interest in Inuvik Gas and $3 million of pre-tax provisions related to assets in the Ikhil Joint Venture.

CORPORATE

Three Months Ended December 31

In the Corporate segment, normalized EBITDA for the fourth quarter of 2016 was a loss of $8 million, compared to $4 million in the fourth quarter of 2015. The increase was mainly due to higher employee incentive compensation expense as a result of the Corporation achieving its key strategic objectives for 2016.

Year Ended December 31

In the Corporate segment, normalized EBITDA for the year ended December 31, 2016 was a loss of $24 million, consistent with the year ended December 31, 2015. Cost savings from the Workforce Restructuring in June 2016 were largely offset by higher employee incentive compensation expense for the year ended December 31, 2016 as compared to 2015.

No provisions on equity investments were recorded for the year ended December 31, 2016 in the Corporate segment. For the year ended December 31, 2015, AltaGas recorded a pre-tax charge of $35 million related to the investment in common shares of Painted Pony.

INVESTED CAPITAL

					Three Months Ended December 31, 2016
($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
Invested capital:					
Property, plant and equipment	**$ 25**	**$ 51**	**$ 45**	**$ 1**	**$ 122**
Intangible assets	**1**	**1**	**1**	**3**	**6**
Long-term investments	**—**	**—**	**—**	**—**	**—**
Invested capital	**26**	**52**	**46**	**4**	**128**
Disposals:					
Property, plant and equipment	**—**	**(1)**	**—**	**—**	**(1)**
Net invested capital	**$ 26**	**$ 51**	**$ 46**	**$ 4**	**$ 127**

($ millions)		Gas		Power		Utilities		Corporate		Total
										Three Months Ended December 31, 2015
Invested capital:										
Property, plant and equipment	$	138	$	538	$	61	$	4	$	741
Intangible assets		1		355		2		2		360
Long-term investments		1		—		—		—		1
Invested capital		140		893		63		6		1,102
Disposals:										
Property, plant and equipment		—		(9)		—		—		(9)
Net invested capital	$	140	$	884	$	63	$	6	$	1,093

During the fourth quarter of 2016, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $128 million, compared to $1,102 million in the same quarter of 2015. The net invested capital was $127 million for the fourth quarter of 2016, compared to $1,093 million in the same quarter in 2015. The decrease in additions to property, plant and equipment and intangible assets in the fourth quarter of 2016 was mainly due to the acquisition of the San Joaquin Facilities in November 2015.

The invested capital in the fourth quarter of 2016 included maintenance capital of $4 million (2015 - $4 million) in the Gas segment and $4 million (2015 - $2 million) in the Power segment.

($ millions)		**Gas**		**Power**		**Utilities**		**Corporate**		**Total**
										Year Ended December 31, 2016
Invested capital:										
Property, plant and equipment	**$**	**287**	**$**	**96**	**$**	**114**	**$**	**4**	**$**	**501**
Intangible assets		**3**		**15**		**2**		**6**		**26**
Long-term investments		**235**		**—**		**—**		**—**		**235**
Invested capital		**525**		**111**		**116**		**10**		**762**
Disposals:										
Property, plant and equipment		**(94)**		**(1)**		**(1)**		**—**		**(96)**
Net invested capital	**$**	**431**	**$**	**110**	**$**	**115**	**$**	**10**	**$**	**666**

($ millions)		Gas		Power		Utilities		Corporate		Total
										Year Ended December 31, 2015
Invested capital:										
Property, plant and equipment	$	263	$	702	$	186	$	9	$	1,160
Intangible assets		3		376		4		13		396
Long-term investments		10		—		—		—		10
Invested capital		276		1,078		190		22		1,566
Disposals:										
Property, plant and equipment		—		(9)		(1)		—		(10)
Net invested capital	$	276	$	1,069	$	189	$	22	$	1,556

For the year ended December 31, 2016, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $762 million, compared to $1,566 million in 2015. The 2016 actual capital expenditures for property, plant and equipment and intangible assets were $527 million as compared to AltaGas' previous guidance of $550 million to $600 million. The decrease was mainly due to timing of spending on certain growth projects. The decrease in additions to property, plant and equipment and intangible assets in 2016 as compared to 2015 was mainly as a result of the acquisition of the San Joaquin Facilities in November 2015. The increase in long-term investments in 2016 mainly relates to the investment in Petrogas Preferred Shares and the investment in Tidewater. As part of the Tidewater Gas Asset Disposition, AltaGas received non-cash consideration of approximately $65 million in the form of Tidewater common shares as at February 29, 2016. The net invested capital was $666 million for the year ended December 31, 2016, compared to $1,556 million in the same period of 2015.

The invested capital for the year ended December 31, 2016 included maintenance capital of $5 million (2015 - $23 million) in the Gas segment and $15 million (2015 - $4 million) in the Power segment. Gas segment maintenance capital included $8 million related to the Harmattan facility turnaround in 2015, while there were no major turnaround activities in the Gas segment for the year ended December 31, 2016. The increase in the Power segment maintenance capital was mainly due to a planned turnaround at the San Joaquin Facilities in 2016.

RISK MANAGEMENT

AltaGas is exposed to various market risks in the normal course of operations that could impact earnings and cash flows. At times, AltaGas will enter into financial derivative contracts to manage exposure to fluctuations in commodity prices and foreign exchange rates. The Board of Directors of AltaGas has established a risk management policy for the Corporation establishing AltaGas' risk management control framework. Financial derivative instruments are governed under, and subject to, this policy. As at December 31, 2016 and December 31, 2015, the fair values of the Corporation's derivatives were as follows:

($ millions)	**December 31, 2016**	December 31, 2015
Natural gas	**$ 4**	$ 3
Storage optimization	**(3)**	3
NGL frac spread	**(12)**	—
Power	**30**	20
Foreign exchange	**—**	(1)
Net derivative asset	**$ 19**	$ 25

Commodity Price Contracts

From time to time, the Corporation executes gas, power, and other commodity contracts to manage its asset portfolio and lock in margins from back-to-back purchase and sale agreements. The fair value of power, natural gas, and NGL derivatives was calculated using estimated forward prices from published sources for the relevant period. AltaGas has not elected hedge accounting for any of its derivative contracts currently in place. Changes in the fair value of these derivative contracts are recorded in the Consolidated Statements of Income in the period in which the change occurs.

The Power segment has various fixed price power purchase and sale contracts in the Alberta market, which are expected to be settled over the next five years. The average Alberta spot price for the year ended December 31, 2016 was approximately $18/MWh (2015 – $33/MWh).

The Corporation also executes fixed-for-floating NGL frac spread swaps to manage its exposure to frac spreads. The financial results of several extraction plants are affected by fluctuations in NGL frac spreads. The average indicative spot NGL frac spread for the year ended December 31, 2016 was $8/Bbl (2015 – $5/Bbl). The average NGL frac spread realized by AltaGas in 2016 was approximately $7/Bbl (2015 - $18/Bbl). In 2016, AltaGas hedged approximately 1,100 Bbls/d of its volumes exposed to frac spreads at an average price of $24/Bbl, excluding basis differentials. For 2017, AltaGas currently has frac hedges in place to hedge approximately 5,450 Bbls/d at an average price of $23/Bbl, excluding basis differentials.

Foreign Exchange

AltaGas has foreign operations whereby the functional currency is the U.S. dollar. As a result, the Corporation's earnings, cash flows, and other comprehensive income are exposed to fluctuations resulting from changes in foreign exchange rates. This risk is partially mitigated by AltaGas' U.S. dollar-denominated debt and preferred shares. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates. As at

December 31, 2016, AltaGas had outstanding foreign exchange forward contracts for US$5 million at an average rate of $1.26 Canadian per U.S. dollar which are expected to be settled over the next four months.

In addition, as at December 31, 2016, management designated US$301 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2015 - US$724 million). U.S. dollar denominated long-term debt instruments have been designated as a hedge of the net investment in foreign subsidiaries. This designation has the effect of mitigating volatility on net income by offsetting foreign exchange gains and losses on U.S. dollar denominated long-term debt and foreign net investment. For the year ended December 31, 2016, AltaGas incurred an after-tax unrealized gain of $34 million arising from the translation of debt in other comprehensive income (2015 – after-tax unrealized loss of $99 million).

The Effects of Derivative Instruments on the Consolidated Statements of Income

The following table presents the unrealized gains (losses) on derivative instruments as recorded in the Corporation's Consolidated Statements of Income:

	Three Months Ended December 31		Year Ended December 31	
($ millions)	**2016**	2015	**2016**	2015
Natural gas	**$ 2**	$ 1	**$ —**	$ 7
Storage optimization	**(2)**	—	**(5)**	(1)
NGL frac spread	**(9)**	(5)	**(12)**	(3)
Power	**(3)**	12	**5**	6
Heat rate	**—**	—	**—**	—
Foreign exchange	**—**	—	**1**	—
	$ (12)	$ 8	**$ (11)**	$ 9

Please refer to Note 19 of the 2016 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities.

Corporation Risks

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

Risks	Strategies and Organizational Capability to Mitigate Risks
Operational	• Maintain diversification across Gas, Power and Utilities • Acquire large working interests to control and optimize operations and maximize efficiencies • Contractual provisions often provide for recovery of operating costs • Centralized procurement strategy to reduce costs • Maintain control over operational decisions, operating costs and capital expenditures by operating certain jointly-owned facilities • Maintain standard operating practices, assess and document employee competency, and maintain formal inspection, maintenance, safety and environmental programs • Purchase business interruption insurance • Fixed price operating and maintenance contracts with equipment manufacturers • Hedging strategy used to balance price and operating risk
Construction	• Major projects group manages and monitors significant construction projects • Strong in-house project control and management framework • Appropriate internal management structure and processes • Engage specialists in designing and building major projects • Contractual arrangements to mitigate cost and schedule risks

Risks	Strategies and Organizational Capability to Mitigate Risks
Liquidity	• Forecast cash flow on a continuous basis to maintain adequate cash balances to fund financial obligations as they come due and to support business operations • Maintain financial flexibility and liquidity needs through a variety of sources including internally-generated cash flows, DRIP, access to credit facilities, and long-term debt and equity issuances • Execute financing plans and strategies to maintain and improve credit ratings to minimize financing costs and support ready access to capital markets
Foreign exchange	• Issue long term debt and preferred shares in U.S. dollars which hedge the Corporation's net investment in U.S. subsidiaries • Employ hedging practices such as entering foreign exchange forward contracts
Interest rates	• Optimize financing plans to maintain and improve credit ratings to minimize interest costs • Monitor and proactively manage the Corporation's debt maturity profile • Employ hedging practices such as entering into interest rate swaps • Maintain financial flexibility and access to multiple credit facilities and continually monitor covenant compliance
Long-term natural gas volume declines	• Long-term contracts such as take-or-pay, area of mutual interest, geographic franchise with economic out • Increase market share by expanding existing facilities or acquiring or constructing new facilities • Increase geographic and customer diversity to reduce exposure to any one individual customer or area of the WCSB • Strategically locate facilities to provide secure access to gas supply • Capitalize on integrated aspects of AltaGas' business to increase volumes through its processing facilities
Volume of power generated	• PPAs for the Blythe, San Joaquin, Ripon, and Brush facilities include specified target availability levels and pay fixed capacity payments upon achieving target availability, and as a result, volumes of power sold have a minimal impact on the Corporation • Diversification of fuel sources and geography • Hedging strategy to balance price and operating risk • Undertake extensive studies to support investment decisions
Commodity price	• Contracting terms, processing, storage and transportation fees independent of commodity prices through fee-for-service, take-or-pay, fixed-fee or cost-of-service provisions • Hedging strategy with hedge targets approved by the Board of Directors • Monitor hedge transactions through Risk Management Committee • AltaGas' Commodity Risk Policy prohibits transactions for speculative purposes • Employ hedging practices to reduce exposure to commodity prices and volatility and lock in margins when the opportunity arises to increase profitability and reduce earnings volatility • Employ strong systems and processes for monitoring and reporting compliance with the Commodity Risk Policy • In-depth knowledge and experience of transportation systems, natural gas, NGL and power markets where AltaGas operates • Hedge power costs • Direct marketing to end-use commercial and industrial customers • Execute long-term inflation adjusted electricity purchase arrangements with power buyers
Counterparty	• Strong credit policies and procedures • Continuous review of counterparty creditworthiness • Establish credit thresholds using appropriate credit metrics • Closely monitor exposures and impact of price shocks on liquidity • Build a diverse customer and supplier base

Risks	Strategies and Organizational Capability to Mitigate Risks
	• Active accounts receivable monitoring and collections processes in place • Credit terms included in contracts
Weather	• Anticipated volumes are determined based on the 20-year rolling average for weather for the Canadian utilities and 15 years for SEMCO Gas and 10 years for ENSTAR • PNG has a weather normalization account for residential and small commercial customers
Regulatory and First Nations	• Regulatory and commercial personnel monitor and manage regulatory issues • Proactive regulatory and government relations group, strong working relationships with First Nations, stakeholders, and regulators • Build risk mitigation into contracts where appropriate • Skilled regulatory department retained • Use of expert third parties when needed
Environment and safety	• Strong safety and environmental management systems • Continuous process improvement strategy employed • Focus on mitigating the impact of the climate change regulations • Zero tolerance safety policies for staff and contractors and reviews of past safety practices for contractors • Purchase and maintain general liability and business interruption insurance • Pipeline and asset integrity programs are in place
Labour relations	• Maintain access to strong labour markets to attract qualified talent • Positive employee relations to retain existing talent and maintain strong relations with unions
Cyber Security	• Continuous monitoring of the Corporations infrastructure, technologies and data • Ongoing cyber security communications and training to staff • Conducting third-party vulnerability and cyber security tests • Corporate threat detection and incident response protocols
Litigation	• Proactive management of lawsuits and other claims • Continuous monitoring of defense and settlement costs of lawsuits and claims • Strong in-house legal department • Use of expert third parties when needed
External Stakeholder Relations	• Proactive stakeholder relations and communications groups, strong working relationships with First Nations, stakeholders, and regulators • Strong commitment to creating social value • Strong safety and environmental management systems

LIQUIDITY

	Year Ended December 31	
($ millions)	**2016**	2015
Cash from operations	**$ 456**	$ 501
Investing activities	**(752)**	(1,516)
Financing activities	**21**	930
Effect of exchange rate	**—**	7
Decrease in cash and cash equivalents	**$ (275)**	$ (78)

Cash from Operations

Cash from operations decreased by $45 million for the year ended December 31, 2016 compared to 2015 primarily due to the unfavorable variance in the net change in operating assets and liabilities, partially offset by higher earnings and higher distributions from equity investments. The net reduction in cash inflow was primarily due to lower cash flows derived from movements in other operating assets due to a higher deferred lease receivable balance associated with the Townsend Facility entering commercial service in 2016 and higher refundable deposits related to certain energy export projects. In addition, the net change in operating assets and liabilities was impacted by movements in accounts receivable, customer deposits, regulatory assets/liabilities, and inventory related to the Utilities segment due to warmer weather in 2016 compared to 2015.

Working Capital

($ millions except current ratio)		**December 31, 2016**		December 31, 2015
Current assets	**$**	**739**	$	1,038
Current liabilities		**996**		948
Working capital (deficiency)	**$**	**(257)**	$	90
Working capital ratio		**0.74**		1.09

The decrease in working capital ratio was primarily due to the decrease in cash and cash equivalents, as well as a higher current portion of long-term debt due, partially offset by the decrease in accounts payable and an increase in inventory as compared to December 31, 2015. Cash was primarily used to reduce AltaGas' total debt level. During the year ended December 31, 2016, AltaGas used cash to repay the US$200 million MTNs, which matured in the first quarter of 2016 and the U.S. Libor loans under the $1.4 billion revolving credit facility. In addition, the completion of the Tidewater Gas Asset Disposition, which was previously classified as assets held for sale also impacted the working capital ratio as a part of the consideration received for the sale was non-cash. This was partially offset by the reclassification of approximately $70 million of non-current assets to current for the planned sale of certain non-core transmission pipelines as at December 31, 2016. AltaGas' working capital will fluctuate in the normal course of business and the working capital deficiency will be funded using cash flow from operations, DRIP and available credit facilities as required.

Investing Activities

Cash used in investing activities for the year ended December 31, 2016 was $752 million, compared to $1,516 million in 2015. Investing activities for the year ended December 31, 2016 primarily included approximately $507 million in additions to property, plant, and equipment, AltaGas' $150 million investment in Petrogas Preferred Shares, a $63 million loan to Petrogas under the $100 million interest bearing secured loan facility provided to Petrogas, approximately $24 million in additions to intangible assets, approximately $21 million for the purchase of EEEP, approximately $20 million of contributions to AltaGas' equity investments, partially offset by cash inflow of approximately $29 million, net of transaction costs, from the Tidewater Gas Asset Disposition. Investing activities for the year ended December 31, 2015 primarily included expenditures of $916 million for business acquisitions, $614 million for property, plant, and equipment, and $38 million for intangible assets, partially offset by cash inflow of $50 million relating to the maturity of a short-term investment and $10 million from disposition of assets.

Financing Activities

Cash from financing activities for the year ended December 31, 2016 was $21 million, compared to $930 million in 2015. Financing activities for the year ended December 31, 2016 were primarily comprised of net proceeds from the issuance of common shares of $604 million (including common shares issued through the DRIP), net proceeds from the issuance of MTNs of $348 million, and borrowings from credit facilities of $327 million, partially offset by the repayment of $884 million of long-term debt. Financing activities for the year ended December 31, 2015 were primarily comprised of net proceeds from issuance of common shares of $403 million and preferred shares of $196 million, net proceeds from the issuance of MTNs of $155 million, borrowings from credit facilities of $910 million and short-term debt of $47 million, partially offset by repayments of long-term debt of $476 million. Total dividends paid to common and preferred shareholders of AltaGas for the year ended December 31, 2016 were $365 million, compared to $296 million for the same period in 2015, of which $174 million was reinvested through the DRIP during the year ended December 31, 2016 (2015 - $96 million). The increase in dividends paid was due to more common shares and preferred shares outstanding and dividend increases on common shares declared in 2015 and 2016. The increase in the amounts reinvested through the DRIP for the year ended December 31, 2016 compared to 2015 was due to the activation of the Premium Dividend™ program effective May 17, 2016. Please refer to Note 20 of the 2016 Annual Consolidated Financial Statements for more information about the DRIP.

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CAPITAL RESOURCES

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

The use of debt or equity funding is based on AltaGas' capital structure, which is determined by considering the norms and risks associated with operations and cash flow stability and sustainability.

($ millions)	December 31, 2016	December 31, 2015
Short-term debt	$ 129	$ 131
Current portion of long-term debt	383	288
Long-term debt(1)	3,367	3,732
Total debt	3,879	4,151
Less: cash and cash equivalents	(19)	(293)
Net debt	$ 3,860	$ 3,858
Shareholders' equity	4,581	4,168
Non-controlling interests	35	35
Total capitalization	$ 8,476	$ 8,061
Debt-to-total capitalization (%)	46	48

(1) Net of debt issuance costs of $14 million as at December 31, 2016 (December 31, 2015 - $15 million).

On April 7, 2016, AltaGas issued $350 million of MTNs. The MTNs carry a coupon rate of 4.12 percent and will mature on April 7, 2026. Net proceeds were used to pay down existing indebtedness under AltaGas' credit facility and for general corporate purposes.

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. Net proceeds were used to partially fund AltaGas' capital growth program, reduce existing indebtedness under AltaGas' credit facility and for general corporate purposes.

On February 22, 2017, AltaGas closed a public offering of 12,000,000 cumulative 5-year minimum rate reset preferred shares, Series K, at a price of $25 per Series K preferred share for aggregate gross proceeds of $300 million. Net proceeds will be used to reduce existing indebtedness and for general corporate purposes.

As at December 31, 2016, AltaGas' total debt primarily consisted of outstanding MTNs of $2.8 billion (December 31, 2015 - $2.8 billion), PNG debenture notes of $43 million (December 31, 2015 - $47 million), SEMCO long-term debt of $500 million (December 31, 2015 - $522 million) and $501 million drawn under the bank credit facilities (December 31, 2015 - $811 million). In addition, AltaGas had $161 million of letters of credit (December 31, 2015 - $147 million) outstanding.

As at December 31, 2016, AltaGas' total market capitalization was approximately $5.6 billion based on approximately 167 million common shares outstanding and a closing trading price on December 31, 2016 of $33.90 per common share.

AltaGas' earnings interest coverage for the rolling 12 months ended December 31, 2016 was 2.4 times (12 months ended December 31, 2015 – 1.5 times).

Credit Facilities

($ millions)	Borrowing capacity	Drawn at December 31, 2016	Drawn at December 31, 2015
Demand operating facilities	$ 70	$ 4	$ 4
Extendible revolving letter of credit facility	150	49	56
Letter of credit demand facility	150	104	80
PNG operating facility	25	10	10
AltaGas Ltd. revolving credit facility (1)	1,400	378	690
AltaGas US$ extendible revolving term credit facility (1) (2)	300	—	—
SEMCO Energy US$ unsecured credit facility (1) (2)	150	117	118
	$ 2,245	$ 662	$ 958

(1) Amount drawn at December 31, 2016 converted at the month-end rate of 1 U.S. dollar = 1.3427 Canadian dollar (December 31, 2015 - 1 U.S. dollar = 1.3840 Canadian dollar).

(2) Borrowing capacity assumed at par.

All of the borrowing facilities have covenants customary for these types of facilities, which must be met at each quarter end. AltaGas and its subsidiaries have been in compliance with all financial covenants each quarter since the establishment of the facilities.

The following table summarizes the Corporation's primary financial covenants as defined by the credit facility agreements:

Ratios	Debt covenant requirements	**As at December 31, 2016**
Bank debt-to-capitalization(1)	not greater than 65 percent	45.4%
Bank EBITDA-to-interest expense (1) (2)	not less than 2.5x	4.1
Bank debt-to-capitalization (SEMCO)(3)	not greater than 60 percent	45.3%
Bank EBITDA-to-interest expense (SEMCO)(3)	not less than 2.25x	6.6

(1) Calculated in accordance with the Corporation's credit facility agreement, which is available on SEDAR at www.sedar.com.

(2) Estimated, subject to final adjustments.

(3) Bank EBITDA-to-interest expense (SEMCO) and Bank debt-to-capitalization (SEMCO) are calculated based on SEMCO's consolidated financial statements and are calculated similar to Bank debt-to-capitalization and Bank EBITDA-to-interest expense.

On August 10, 2015, a $5 billion base shelf prospectus was filed. The purpose of the base shelf prospectus is to facilitate timely offerings of certain types of future public debt and/or equity issuances during the 25-month period that the base shelf prospectus remains effective, by disclosing standardized information required for such issuances. As at December 31, 2016, $3.7 billion remains available under the base shelf prospectus. On February 3, 2017, AltaGas closed a public offering of 67,800,000 subscription receipts, on a bought deal basis, for total gross proceeds of approximately $2.1 billion and on February 22, 2017, AltaGas closed a public offering of Series K preferred shares for gross proceeds of $300 million, decreasing the amount available under the base shelf prospectus to $1.3 billion.

CONTRACTUAL OBLIGATIONS

December 31, 2016 Payments Due by Period

($ millions)	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Short-term debt [1]	$ 129	$ 129	$ —	$ —	$ —
Long-term debt [1]	3,765	384	397	1,345	1,639
Operating leases	88	33	24	9	22
Purchase obligations	2,289	390	689	616	594
Capital project commitments	34	34	—	—	—
Pension plan and retiree benefits [2]	21	21	—	—	—
Other liabilities	174	22	25	22	105
Total contractual obligations [3]	$ 6,500.0	$ 1,013.0	$ 1,135.0	$ 1,992.0	$ 2,360.0

(1) Excludes interest payments and deferred financing costs.

(2) Assumes only required payments will be made into the pension plans in 2017. Contributions are made in accordance with independent actuarial valuations.

(3) US dollar commitments have been converted to Canadian dollar using the December 31, 2016 exchange rate.

RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Refer to Note 26 of the 2016 Annual Consolidated Financial Statements for the amounts due to or from related parties on the Consolidated Balance Sheets and the classification of revenue, income, and expenses in the Consolidated Statements of Income.

CREDIT RATINGS

On January 26, 2017, Standard & Poor's (S&P) reaffirmed the BBB with a Negative Outlook and P-3 (High) ratings for AltaGas.

On January 26, 2017, DBRS Limited (DBRS) revised the BBB and the Pfd-3 rating of AltaGas to Under Review with Developing Implications.

On November 19, 2016, DBRS reaffirmed the BBB rating with a stable trend for AltaGas.

On December 16, 2015, S&P revised the BBB rating to BBB with a Negative Outlook and reaffirmed the P-3 (High) rating for AltaGas.

On November 19, 2015, S&P commenced rating of the Series I Preferred Shared with a rating of P-3 (High).

On November 19, 2015, DBRS reaffirmed the BBB rating with a stable trend for AltaGas.

On November 18, 2015, DBRS commenced rating of the Series I Preferred Shares with a rating of Pfd-3.

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

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.

According to the S&P rating system, an obligation rated BBB exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. A P-3 rating by S&P is the third highest of eight categories granted by S&P. According to the S&P rating system, while securities rated P-3 are regarded as having significant speculative characteristics, they are less vulnerable to non-payment than other speculative issues. However, it faces ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. The ratings from P-1 to P-5 may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

The credit ratings accorded to the securities by the rating agencies are not recommendations to purchase, hold or sell the securities in as much as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant.

SHARE INFORMATION

	As at February 17, 2017
Issued and outstanding	
Common shares	168,168,409
Preferred Shares	
Series A	5,511,220
Series B	2,488,780
Series C	8,000,000
Series E	8,000,000
Series G	8,000,000
Series I	8,000,000
Subscription Receipts	80,710,000
Issued	
Share options	4,064,761
Share options exercisable	3,237,633

DIVIDENDS

AltaGas declares and pays a monthly dividend to its common shareholders. Dividends on preferred shares are paid quarterly. Dividends are at the discretion of the Board of Directors and dividend levels are reviewed periodically, giving consideration to the ongoing sustainable cash flow from operating activities, maintenance and growth capital expenditures, and debt repayment requirements of AltaGas.

On July 20, 2016, the Board of Directors approved an increase in the monthly dividend to $0.175 per common share from $0.165 per common share effective with the August 2016 dividend.

On February 22, 2017, AltaGas closed a public offering of the Series K preferred shares. Holders of the Series K preferred shares will be entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding March 31, 2022 at an annual rate of 5.0 percent, payable on the last day of March, June, September and December, as and when declared by the Board of Directors of AltaGas. The first quarterly dividend payment is payable on June 30, 2017 in the amount of $0.4384 per Series K Preferred Share. The dividend rate will reset on March 31, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 3.8 percent, provided that, in any event, such rate shall not be less than 5.0 percent per annum.

The following table summarizes AltaGas' dividend declaration history:

Dividends

Year ended December 31 *($ per common share)*		**2016**		2015
First quarter	**$**	**0.49500**	$	0.44250
Second quarter		**0.49500**		0.46750
Third quarter		**0.51500**		0.48000
Fourth quarter		**0.52500**		0.49500
Total	**$**	**2.03000**	$	1.88500

Series A Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		**2016**		2015
First quarter	**$**	**0.21125**	$	0.31250
Second quarter		**0.21125**		0.31250
Third quarter		**0.21125**		0.31250
Fourth quarter		**0.21125**		0.21125
Total	**$**	**0.84500**	$	1.14875

Series B Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		**2016**		2015
First quarter	**$**	**0.19269**	$	—
Second quarter		**0.19393**		—
Third quarter		**0.20109**		—
Fourth quarter		**0.19921**		0.19156
Total	**$**	**0.78692**	$	0.19156

Series C Preferred Share Dividends

Year ended December 31 *(US$ per preferred share)*		**2016**		2015
First quarter	**$**	**0.27500**	$	0.27500
Second quarter		**0.27500**		0.27500
Third quarter		**0.27500**		0.27500
Fourth quarter		**0.27500**		0.27500
Total	**$**	**1.10000**	$	1.10000

Series E Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		**2016**		2015
First quarter	**$**	**0.31250**	$	0.31250
Second quarter		**0.31250**		0.31250
Third quarter		**0.31250**		0.31250
Fourth quarter		**0.31250**		0.31250
Total	**$**	**1.25000**	$	1.25000

Series G Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		**2016**		2015
First quarter	**$**	**0.296875**	$	0.296875
Second quarter		**0.296875**		0.296875
Third quarter		**0.296875**		0.296875
Fourth quarter		**0.296875**		0.296875
Total	**$**	**1.187500**	$	1.187500

Series I Preferred Share Dividends

Year ended December 31 *($ per preferred share)*		**2016**		2015
First quarter	**$**	**0.463870**	$	—
Second quarter		**0.328125**		—
Third quarter		**0.328125**		—
Fourth quarter		**0.328125**		—
Total	**$**	**1.448245**	$	—

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of AltaGas' Consolidated Financial Statements requires the use of estimates and assumptions that have been made using careful judgment. AltaGas’ significant accounting policies are contained in the notes to the 2016 Annual Consolidated Financial Statements. Certain of these policies involve critical accounting estimates as a result of the requirement to make particularly subjective or complex judgments about matters that are inherently uncertain, and because of the likelihood that materially different amounts could be reported under different conditions or using different assumptions.

Significant estimates and judgments made by management in the preparation of the Consolidated Financial Statements are outlined below:

Fair Value of Financial Instruments

Fair value is defined as the amount of consideration that would be agreed upon in an arms-length transaction, other than a forced sale or liquidation, between knowledgeable, willing parties who are under no compulsion to act. The best evidence of fair value is a quoted bid or ask price, as appropriate, in an active market. Fair value based on unadjusted quoted prices in an active market requires minimal judgment by management. Where bid or ask prices in an active market are not available, management’s judgment on valuation inputs is necessary to determine fair value. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity prices and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, and currency exchange. The forward curves used to mark these derivative instruments to market are vetted against public sources. Where observable market data is not available, AltaGas uses valuation techniques which require significant judgment by management. Changes in estimates and assumptions about these inputs could affect the reported fair value.

Depreciation and Amortization

Depreciation and amortization of property, plant, and equipment and intangible assets are based on management's judgment of the estimated useful life of the assets. When it is determined that assigned asset lives do not reflect the estimated remaining period of benefit, prospective changes are made to the depreciable lives of those assets. For regulated entities, amortization rates are generally prescribed by the applicable regulatory authority. There are a number of uncertainties inherent in estimating the remaining useful life of certain assets and changes in assumptions could result in material adjustments to the amount of amortization that AltaGas recognizes from period to period.

Asset Retirement Obligations

AltaGas records liabilities relating to asset retirement obligations when there is a legal obligation. In estimating the obligations, management is required to make assumptions regarding inflation and discount rates, ultimate amounts and timing of settlements, and expected changes in environmental laws and regulation. A change in any of these estimates could have a material impact on AltaGas' Consolidated Financial Statements.

Asset Impairment

AltaGas reviews long-lived assets and intangible assets with finite lives whenever events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Recoverability is determined based on an estimate of undiscounted cash flows, and measurement of an impairment loss is determined based on the fair value of the assets. The determination of fair value requires management to make assumptions about future cash inflows and outflows over the life of an asset. Any changes to the assumptions used for the future cash flow could result in revisions to the evaluation of the recoverability of the long-lived assets or intangible assets and the recognition of an impairment loss in the Consolidated Financial Statements.

AltaGas also tests goodwill for impairment annually or more frequently if events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is less than its carrying value. The Corporation has the option to first assess qualitative factors to determine whether it is necessary to perform the two-step goodwill impairment test. If the two-step goodwill impairment test is performed, the first step is to compare the fair value of the Corporation's reporting units and to the carrying values. If the carrying value of a reporting unit, including allocated goodwill exceeds its fair value, goodwill impairment is measured as the excess of the carrying value amount of the reporting unit's allocated goodwill over the implied fair value of the goodwill. The fair value used in the quantitative impairment test of goodwill requires estimating future cash flows as well as appropriate discount rates. AltaGas has assessed goodwill for impairment as at December 31, 2016 and determined that no write-down was required.

Income Taxes

The Corporation is subject to the provisions of the Income Tax Act (Canada) for purposes of determining the amount of income that will be subject to tax in Canada and the Internal Revenue Code (U.S.) for the purposes of determining the amount of income that will be subject to tax in the United States. The determination of AltaGas' and its subsidiaries' provision for income taxes requires the application of these complex rules.

Substantial deferred income tax assets and liabilities are recognized in the Consolidated Financial Statements. The recognition of deferred tax assets depends on the assumption that future earnings will be sufficient to realize the deferred benefit. A valuation allowance is recorded against deferred tax assets where all or a portion of that asset is not expected to be realized. The amount of the deferred tax asset or liability recorded is based on management's best estimate of the timing of the realization of the assets or liabilities.

If management's interpretation of tax legislation differs from that of tax authorities, or if timing of reversals is not as anticipated, the provision for income taxes could increase or decrease in future periods. See Note 16 to the 2016 Annual Consolidated Financial Statements.

Pension Plans and Post-retirement Benefits

The determination of pension plan obligations and expense is based on a number of actuarial assumptions. Two critical assumptions are the expected long-term rate-of-return on plan assets and the discount rate applied to pension plan obligations. For post-retirement benefit plans, which provide for certain health care premiums and life insurance benefits for qualifying retired employees and which are not funded, critical assumptions in determining post-retirement obligations and expense are the discount rate and the assumed health care cost trend rates. Notes 2 and 24 to the 2016 Annual Consolidated Financial Statements include information on the assumptions used for the purposes of recording the funding status of the plans and the associated expenses.

Regulatory Assets and Liabilities

SEMCO, ENSTAR and CINGSA, AUI, Heritage Gas and PNG engage in the delivery and sale of natural gas and are regulated by the following regulatory agencies: MPSC and RCA, AUC, NSUARB and BCUC, respectively.

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

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate-setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate-setting process.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2016, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Updates (ASU):

- ASU No. 2014-12, “Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period”, which requires a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2015-01, “Income Statement – Extraordinary and Unusual Items”, which eliminates the concept of extraordinary items. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2015-02, “Consolidation: Amendments to Consolidation Analysis”. The amendments in this ASU affect all reporting entities that are required to evaluate whether certain legal entities should be consolidated. The amendments a) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; b) eliminate the presumption that a general partner should consolidate a limited partnership; c) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships; and d) provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities (i.e. money market and other investment funds). The adoption of this ASU did not have a material impact on AltaGas’ consolidated financial statements; and

- ASU No. 2016-17, “Consolidation: Interests Held through Related Parties That Are under Common Control”. The amendment in this ASU revises the consolidation requirements that apply to a single decision maker’s evaluation of interests held through related parties that are under common control. The revised guidance requires that a single decision maker report all of its direct variable interests in a VIE and, on a proportionate basis, its indirect variable interests in a VIE held through related parties, including related parties that are under common control with the reporting entity. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In July 2015, FASB issued ASU No. 2015-11 "Inventory - Simplifying the Measurement of Inventory". The amendment in this ASU requires an entity to measure inventory at the lower of cost and net realizable value. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, prospectively. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In May 2014, FASB issued ASU No. 2014-09 "Revenue from Contracts with Customers", which will replace numerous requirements in U.S. GAAP, including industry-specific requirements, and provide companies with a single revenue recognition model for recognizing revenue from contracts with customers. The core principle of the amendments in this ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, FASB issued ASU No. 2016-08 "Principal versus Agent Consideration". The amendments in this ASU clarify the implementation guidance on the principal versus agent considerations in the new revenue recognition standard. In April 2016, FASB issued ASU No. 2016-10 "Identifying Performance Obligation and Licensing", which reduces the complexity when applying the guidance for identifying performance obligations and improves the operability and understandability of the license implementation guidance. In May 2016, FASB issued ASU No. 2016-12 "Narrow Scope Improvements and Practical Expedients", clarifying several implementation issues, including collectability, presentation of sales taxes, non-cash consideration, contract modification, completed contracts, and transition. In December 2016, FASB issued ASU No. 2016-20 "Technical Corrections and Improvements", which makes minor technical corrections and improvements to the new revenue standard. The new revenue standard will be effective for annual and interim periods beginning on or after December 15, 2017. FASB permits adoption of the standard as early as the original effective date of December 15, 2016. Although early adoption is permitted, AltaGas will adopt ASU No. 2014-09 during the first quarter of 2018. In 2016, AltaGas established a cross-functional implementation team consisting of representatives from across all the operating segments. A preliminary scoping exercise was completed for AltaGas' operating segments and, while AltaGas is continuing to assess all potential impacts of the standard, AltaGas anticipates that the new standard will mostly impact the Gas and Utilities segments with regards to the timing of revenue recognition under the ASU for contracts that have take-or-pay features. AltaGas is still in the process of evaluating these impacts. AltaGas is currently progressing through contract reviews in order to identify and quantify potential differences. AltaGas is also awaiting further guidance from the AICPA Power and Utility Entities Revenue Recognition Task Force related to the income statement presentation of revenue from alternative revenue programs. The ASU permits the use of either the full retrospective or modified retrospective transition method and AltaGas has yet to determine the transition method that will be applied pending the completion of the contract reviews. AltaGas expects to provide more detailed information in its 2017 financial statements as implementation progresses.

In January 2016, FASB issued ASU No. 2016-01 "Recognition and Measurement of Financial Assets and Financial Liabilities" which revises an entity's accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The amendments in this ASU are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Upon adoption, entities will be required to make a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective. The guidance on equity securities without readily determinable fair value will be applied prospectively to all equity investments that exist as of the date of adoption of the standard. Upon adoption, AltaGas will no longer be able to classify equity securities with readily determinable fair values as available-for-sale and any changes in fair value will be reported through earnings instead of other comprehensive income. The remaining provisions of this ASU are not expected to have a material impact on AltaGas' financial statements.

In February 2016, FASB issued ASU No. 2016-02 “Leases”, which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability for all leases with lease terms greater than 12 months. Lessor accounting remains substantially unchanged. The ASU also requires additional disclosures regarding leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-05 “Derivatives and Hedging: Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships”. The amendments in this ASU apply to all entities for which there is a change in the counterparty to a derivative instrument that has been designated as a hedging instrument. This ASU clarifies that a change in the counterparty does not require de-designation of that hedging relationship. The amendments in this ASU are effective for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity has an option to apply for amendments in this ASU on either a prospective basis or a modified retrospective basis. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-06 “Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments”. The amendments in this ASU clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. An entity performing the assessment under the amendments in this ASU is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity should apply the amendment in this ASU on a modified retrospective basis, early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-07 “Equity Method and Joint Ventures Investments: Simplifying the Transition to the Equity Method of Accounting”. The amendments in this ASU eliminate the requirement to retrospectively apply the equity method as a result of an increase in the level of ownership interest or degree of influence. The amendments in this ASU are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. The amendments should be applied prospectively upon their effective date to increases in level of ownership interest or degree of influence. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In March 2016, FASB issued ASU No. 2016-09 “Stock Compensation: Improvements to Employee Share-Based Payment Accounting”. The amendments in this ASU focuses on simplifying several areas of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory withholding requirements, as well as the classification on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2016, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In June 2016, FASB issued ASU No. 2016-13 “Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments”. The amendments in this ASU replace the current “incurred loss” impairment methodology with an “expected loss” model for financial assets measured at amortized cost. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2020, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In August 2016, FASB issued ASU No. 2016-15 “Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments”. The amendments in this ASU clarify the classification of certain cash flow transactions on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2017, and interim periods within those fiscal periods. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In October 2016, FASB issued ASU No. 2016-16 “Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory”. The amendments in this ASU revise the accounting for income tax consequences on intra-entity transfer of assets by requiring an entity to recognize current and deferred tax on intra-entity transfer of assets other than inventory when the transfer occurs. The amendment in this ASU is effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendment in this ASU on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Early adoption is also permitted but can only be adopted in the first interim period of a fiscal year. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In November 2016, FASB issued ASU No. 2016-18 “Statement of Cash Flows: Restricted Cash”. The amendments in this ASU require those amounts deemed to be restricted cash and restricted cash equivalents to be included in the cash and cash equivalents balance on the statement of cash flows. The amendment in this update is effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU retrospectively to each period presented. Early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated cash flow statements.

In January 2017, FASB issued ASU No. 2017-01 “Business Combinations: Clarifying the Definition of a Business”. The amendments in this ASU change the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis on or after the effective date. AltaGas will apply the amendments prospectively.

In January 2017, FASB issued ASU No. 2017-04 “Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment”. The ASU removes Step 2 of the goodwill impairment test, eliminating the requirement to determine the fair value of individual assets and liabilities of a reporting unit to measure the goodwill impairment. An entity should adopt the amendments in this ASU for annual periods beginning after December 15, 2019, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis. Early adoption is permitted. AltaGas will apply the amendments prospectively.

OFF-BALANCE SHEET ARRANGEMENTS

AltaGas is not party to any contractual arrangement under which an unconsolidated entity or a material variable interest in an unconsolidated entity have any obligation under certain guarantee contracts; a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. AltaGas is not party to any variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support or engages in leasing, hedging or research and development services.

In May 2009, the National Energy Board (NEB) issued a decision that set out guiding principles for a mechanism that would set aside funds for pipeline abandonment. It also established a five-year action plan for all NEB-regulated companies. In May 2014, the NEB issued a decision establishing that, by January 1, 2015, all NEB-regulated companies must have a mechanism in place for the accumulation of funds to pay for future pipeline abandonment. AltaGas Holdings Inc., a wholly-owned subsidiary of AltaGas, opted to comply with the NEB decision with a surety bond supplied by a surety company regulated by the Office of the Superintendent of Financial Institutions in the amount of $30 million.

In October 2014, AltaGas issued two guarantees with an aggregate maximum liability of approximately US$92 million, guaranteeing Heritage Gas’ payment obligations under a transportation agreement entered into by Heritage Gas with Spectra Energy for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems.

DISCLOSURE CONTROLS AND PROCEDURES (DCP) AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

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

AltaGas' management, including the Chief Executive Officer and the Chief Financial Officer, have designed, or caused to be designed under their supervision, DCP and ICFR to provide reasonable assurance that information required to be disclosed by AltaGas in its annual filings, interim filings or other reports to be filed or submitted by it under securities legislation is made known to them, is reported on a timely basis, financial reporting is reliable, and financial statements prepared for external purposes are in accordance with U.S. GAAP.

The ICFR has been designed based on the framework established in the 2013 Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

The Chief Executive Officer and the Chief Financial Officer have evaluated, with the assistance of AltaGas' employees, the effectiveness of AltaGas' DCP and ICFR as at December 31, 2016 and concluded that as at December 31, 2016, AltaGas' DCP and ICFR were effective.

During the fourth quarter of 2016, AltaGas completed the transition of internal controls relating to the San Joaquin Facilities acquired on November 30, 2015. No additional changes were made to AltaGas' ICFR during the fiscal year ended December 31, 2016 that materially affected, or are reasonably likely to materially affect, its ICFR.

It should be noted that a control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues, including instances of fraud, if any, have been detected. The design of any system of controls is also based in part on certain assumptions about the likelihood of future events, and there can be no assurances that any design will succeed in achieving its stated goals under all potential conditions.

SUMMARY OF CONSOLIDATED RESULTS FOR THE EIGHT MOST RECENT QUARTERS (1)

($ millions)	**Q4-16**	Q3-16	Q2-16	Q1-16	Q4-15	Q3-15	Q2-15	Q1-15
Total revenue	**661**	492	426	611	580	452	416	744
Normalized EBITDA(2)	**194**	176	153	178	173	125	107	178
Net income (loss) applicable to common shares	**38**	46	16	55	(54)	20	(22)	66
($ per share)	**Q4-16**	Q3-16	Q2-16	Q1-16	Q4-15	Q3-15	Q2-15	Q1-15
Net income (loss) per common share								
Basic	**0.23**	0.28	0.10	0.38	(0.37)	0.15	(0.16)	0.49
Diluted	**0.23**	0.28	0.10	0.38	(0.37)	0.14	(0.16)	0.49
Dividends declared	**0.53**	0.52	0.50	0.50	0.50	0.48	0.47	0.44

(1) Amounts may not add due to rounding.

(2) Non-GAAP financial measure. See discussion in the "Non-GAAP Financial Measures" section of this MD&A.

AltaGas' quarter-over-quarter financial results are impacted by seasonality, fluctuations in commodity prices, weather, the U.S./Canadian dollar exchange rate, planned and unplanned plant outages, timing of in-service dates of new projects, and acquisition and divestiture activities.

Revenue for the Utilities is generally the highest in the first and fourth quarters of any given year as the majority of natural gas demand occurs during the winter heating season, which typically extends from November to March. The run-of-river hydroelectric facilities in British Columbia are also impacted by seasonal precipitation and snowpack melt, which create periods of high flow during the spring and summer months.

Other significant items that impacted quarter-over-quarter revenue during the periods noted include:

- The acquisition of three natural gas-fired power assets (Ripon, Pomona and Brush II) in the U.S. with a total capacity of 164 MW in the first quarter of 2015;
- The Harmattan and Younger turnarounds in the second quarter of 2015;
- The San Joaquin Facilities acquired on November 30, 2015;
- The commissioning of McLymont in the fourth quarter of 2015;
- The weak NGL commodity prices throughout 2015 and 2016;
- The closing of the Tidewater Gas Asset Disposition on February 29, 2016;
- The stronger U.S. dollar on translated results of the U.S. assets throughout 2015 and 2016;
- The weak Alberta power pool prices throughout 2016;
- The seasonally warmer weather experienced at all of the Utilities in the first quarter of 2016;
- The commencement of commercial operations early in the third quarter of 2016 at the integrated midstream complex at Townsend in northeast British Columbia, including the Townsend Facility, gas gathering line, NGL egress pipelines and truck terminal; and
- The recovery of $7 million of development costs related to the PNG Pipeline Looping Project in the third quarter of 2016.

Net income (loss) applicable to common shares is also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provision on assets and gains or losses on the sale of assets. In addition, net income (loss) applicable to common shares is also impacted by preferred share dividends. For these reasons, the net income (loss) may not necessarily reflect the same trends as revenue. Net income (loss) applicable to common shares during the periods noted was impacted by:

- Higher depreciation and amortization expense due to new assets placed into service or acquired, partially offset by lower depreciation and amortization expense as a result of the Tidewater Gas Asset Disposition on February 29, 2016;
- Higher interest expense mainly due to new assets placed into service and interest no longer eligible for capitalization, and a higher average debt balance since the fourth quarter of 2015 as a result of the acquisition of the San Joaquin Facilities;
- A one-time non-cash expense of $14 million related to the revaluation of deferred income tax liabilities based on the increased Alberta corporate income tax rate from 10 to 12 percent in the second quarter of 2015;
- An after-tax provision of $6 million related to the planned sale of certain development stage wind assets in northern California in the third quarter of 2015;
- After-tax provisions totaling $114 million in the fourth quarter of 2015 related to AltaGas' investment in common shares of Painted Pony, investment in ASTC, investment in its joint ventures with Idemitsu Kosan Co.,Ltd. and the DC LNG Project, certain wind development projects, certain gas processing assets that were held for sale, and AltaGas' one-third interest in Inuvik Gas Ltd. and assets in the Ikhil Joint Venture;
- An after-tax gain on sale of $14 million in the first quarter of 2016 related to the sale of certain non-core natural gas gathering and processing assets located primarily in central and north central Alberta;
- After-tax restructuring charges of $5 million in the second quarter of 2016 related to the Workforce Restructuring; and
- The termination of the Sundance B PPAs effective March 8, 2016 pursuant to the change in law provision of the Sundance B PPAs and as a result, AltaGas recognized an after-tax provision of $4 million on its investment in ASTC to settle the working capital deficiency in the first quarter of 2016. In addition, AltaGas recognized a pre-tax termination expense of $8 million (after-tax $7 million) upon reaching a definitive settlement agreement with the GOA regarding the termination of the Sundance B PPAs in the fourth quarter of 2016. Including the tax recovery on the dissolution of ASTC of $8 million, the after-tax impact on the termination of the Sundance B PPAs was approximately $3 million.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except where noted)	**2016**	2015	2014
Revenue	**2,190**	2,193	2,406
Net income applicable to common shares	**155**	10	96
Basic ($ per share)	**0.99**	0.07	0.75
Diluted ($ per share)	**0.99**	0.07	0.74
Total assets	**10,201**	10,100	8,396
Total long-term financial liabilities	**3,532**	3,899	3,202
Weighted average number of common shares outstanding (millions)	**157**	138	127
Dividends declared per common share ($ per share)	**2.030000**	1.885000	1.690000
Preferred share dividends declared ($ per share)			
Series A	**0.845000**	1.148750	1.250000
Series B	**0.786920**	0.191560	—
Series C	**1.100000**	1.100000	1.100000
Series E	**1.250000**	1.250000	1.307400
Series G	**1.187500**	1.187500	0.586500
Series I	**1.448245**	—	—

Other Information

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
MMBTU	million British thermal unit
PJ	petajoule
US$	United States dollar

ABOUT ALTAGAS

AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. The Corporation creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca.

For further information contact:

Investment Community
1-877-691-7199
investor.relations@altagas.ca

Management's Responsibility for Consolidated Financial Statements

The Consolidated Financial Statements and Management's Discussion and Analysis (MD&A) are the responsibility of the management of AltaGas Ltd. (AltaGas or the Corporation) and have been approved by the Board of Directors of the Corporation. The Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP) and include amounts that are based on management's best estimates and judgments.

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

The MD&A and Consolidated Financial Statements are approved by the Board of Directors after considering the recommendation of the Audit Committee. The Audit Committee of the Board of Directors is composed of independent non-management directors.

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

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

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

(signed) *"David Harris"*

DAVID HARRIS
President and
Chief Executive Officer of
AltaGas Ltd.

(signed) *"Tim Watson"*

TIM WATSON
Executive Vice President and
Chief Financial Officer of
AltaGas Ltd.

February 22, 2017

Independent Auditors' Report

To the Shareholders of AltaGas Ltd.

We have audited the accompanying Consolidated Financial Statements of AltaGas Ltd., which comprise the consolidated balance sheets as at December 31, 2016 and 2015, and the consolidated statements of income, comprehensive income, equity and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of Consolidated Financial Statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian Generally Accepted Auditing Standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Consolidated Financial Statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the Consolidated Financial Statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of AltaGas Ltd. as at December 31, 2016 and 2015 and the results of its operations and its cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Canada
February 22, 2017

Consolidated Balance Sheets

As at *($ millions)*	**December 31, 2016**	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	**$ 19.0**	$ 293.4
Accounts receivable, net of allowances *(note 19)*	**338.8**	333.3
Inventory *(note 5)*	**221.0**	204.0
Restricted cash holdings from customers	**5.0**	5.4
Regulatory assets *(note 17)*	**0.9**	4.3
Risk management assets *(note 19)*	**40.4**	50.4
Prepaid expenses and other current assets	**42.8**	48.3
Assets held for sale *(note 4)*	**70.7**	98.7
	738.6	1,037.8
Property, plant and equipment *(notes 4 and 6)*	**6,734.9**	6,597.9
Intangible assets *(notes 4 and 8)*	**694.3**	735.1
Goodwill *(notes 4 and 9)*	**856.0**	877.3
Regulatory assets *(note 17)*	**329.1**	333.3
Risk management assets *(note 19)*	**24.1**	23.5
Deferred income taxes *(note 16)*	**2.8**	4.5
Restricted cash holdings from customers	**10.1**	12.5
Long-term investments and other assets *(note 10)*	**189.3**	64.3
Investments accounted for by the equity method *(note 11)*	**621.4**	413.3
	$ 10,200.6	$ 10,099.5
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable and accrued liabilities *(note 19)*	**$ 345.8**	$ 383.1
Dividends payable	**29.2**	24.1
Short-term debt *(notes 12 and 19)*	**128.7**	130.7
Current portion of long-term debt *(notes 13 and 19)*	**383.4**	287.5
Customer deposits	**35.5**	41.0
Regulatory liabilities *(note 17)*	**16.6**	21.3
Risk management liabilities *(note 19)*	**32.9**	33.5
Other current liabilities *(notes 15 and 19)*	**23.6**	17.8
Liabilities associated with assets held for sale *(note 4)*	**0.4**	8.7
	996.1	947.7
Long-term debt *(notes 13 and 19)*	**3,366.9**	3,732.4
Asset retirement obligations *(notes 4 and 14)*	**81.6**	67.9
Deferred income taxes *(note 16)*	**621.7**	621.7
Regulatory liabilities *(note 17)*	**170.5**	167.6
Risk management liabilities *(note 19)*	**12.6**	15.7
Other long-term liabilities *(notes 15 and 19)*	**206.3**	206.7
Future employee obligations *(note 24)*	**129.5**	136.9
	$ 5,585.2	$ 5,896.6

As at *($ millions)*		**December 31, 2016**		December 31, 2015
Shareholders' equity				
Common shares, no par values, unlimited shares authorized; 2016 - 166.9 million and 2015 - 146.3 million issued and outstanding *(note 20)*	**$**	**3,773.4**	$	3,168.1
Preferred shares *(note 20)*		**985.1**		985.1
Contributed surplus		**17.4**		16.7
Accumulated deficit		**(600.4)**		(435.4)
Accumulated other comprehensive income (AOCI) *(note 18)*		**405.1**		433.5
Total shareholders' equity		**4,580.6**		4,168.0
Non-controlling interests		**34.8**		34.9
Total equity		**4,615.4**		4,202.9
	$	**10,200.6**	$	10,099.5

Commitments, contingencies and guarantees (note 25).
Subsequent events (note 29).

See accompanying notes to the Consolidated Financial Statements.

Approved by the Board of Directors of AltaGas Ltd.

(signed) *"David W. Cornhill"*

DAVID W. CORNHILL
Director

(signed) *"Robert B. Hodgins"*

ROBERT B. HODGINS
Director

Consolidated Statements of Income

For the year ended December 31 ($ millions except per share amounts)	2016	2015
REVENUE		
Regulated operations	**$ 1,049.9**	$ 1,066.7
Services *(note 23)*	**828.4**	758.5
Sales	**315.6**	357.2
Other revenue	**7.2**	1.0
Unrealized gains (losses) on risk management contracts *(note 19)*	**(11.4)**	9.4
	2,189.7	2,192.8
EXPENSES		
Cost of sales, exclusive of items shown separately	**1,016.9**	1,104.9
Operating and administrative	**509.3**	491.9
Accretion expenses *(notes 14 and 15)*	**11.0**	11.0
Depreciation and amortization *(notes 6 and 8)*	**271.5**	211.9
Provisions on assets *(note 7)*	**—**	53.5
	1,808.7	1,873.2
Income (loss) from equity investments *(note 11)*	**3.4**	(63.4)
Other income (loss) *(note 22)*	**8.6**	(28.7)
Foreign exchange gains	**4.0**	6.0
Interest expense		
Short-term debt	**(3.1)**	(1.1)
Long-term debt	**(147.7)**	(124.4)
Income before income taxes	**246.2**	108.0
Income tax expense *(note 16)*		
Current	**24.4**	23.8
Deferred	**8.4**	24.5
Net income after taxes	**213.4**	59.7
Net income applicable to non-controlling interests	**9.9**	8.6
Net income applicable to controlling interests	**203.5**	51.1
Preferred share dividends	**(48.1)**	(41.2)
Net income applicable to common shares	**$ 155.4**	**$** 9.9
Net income per common share *(note 21)*		
Basic	**$ 0.99**	$ 0.07
Diluted	**$ 0.99**	$ 0.07
Weighted average number of common shares outstanding (millions) *(note 21)*		
Basic	**157.2**	137.7
Diluted	**157.6**	138.7

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Comprehensive Income

For the year ended December 31 ($ millions)		**2016**		2015
Net income after taxes	**$**	**213.4**	$	59.7
Other comprehensive income (loss), net of taxes				
Gain (loss) on foreign currency translation		**(84.2)**		368.2
Unrealized gain (loss) on net investment hedge *(note 19)*		**34.0**		(98.7)
Unrealized losses on cash flow hedges		**—**		(0.2)
Reclassification of gains on cash flow hedges to net income		**—**		(13.1)
Actuarial losses on pension plans and post-retirement benefit (PRB) plans *(note 24)*		**(2.4)**		(0.6)
Reclassification of actuarial losses and prior service costs on defined benefit and PRB plans to net income *(note 24)*		**0.7**		0.6
Unrealized gain (loss) on available-for-sale assets		**22.2**		(24.3)
Other than temporary impairment on available-for-sale assets *(note 10)*		**—**		33.9
Other comprehensive income from equity investees		**1.3**		4.6
Total other comprehensive income (loss) (OCI), net of taxes		**(28.4)**		270.4
Comprehensive income attributable to controlling interests and non-controlling interests, net of taxes	**$**	**185.0**	$	330.1
Comprehensive income attributable to:				
Non-controlling interests	**$**	**9.9**	$	8.6
Controlling interests		**175.1**		321.5
	$	**185.0**	$	330.1

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Equity

For the year ended December 31 ($ millions)		**2016**		2015
Common shares *(note 20)*				
Balance, beginning of year	**$**	**3,168.1**	$	2,759.9
Shares issued for cash on exercise of options		**9.3**		20.8
Shares issued under DRIP [(1)]		**173.6**		96.2
Deferred taxes on share issuance costs		**0.2**		3.3
Shares issued on public offering, net of issuance costs		**422.2**		287.9
Balance, end of year	**$**	**3,773.4**	$	3,168.1
Preferred shares *(note 20)*				
Balance, beginning of year	**$**	**985.1**	$	788.4
Series A converted to Series B		**—**		(60.9)
Series B issued		**—**		60.9
Series I Issued		**—**		195.6
Deferred taxes on share issuance costs		**—**		1.1
Balance, end of year	**$**	**985.1**	$	985.1
Contributed surplus				
Balance, beginning of year	**$**	**16.7**	$	14.9
Share options expense		**1.6**		3.2
Exercise of share options		**(0.7)**		(1.6)
Forfeiture of share options		**(0.2)**		(0.4)
Other		**—**		0.6
Balance, end of year	**$**	**17.4**	$	16.7
Accumulated deficit				
Balance, beginning of year	**$**	**(435.4)**	$	(185.2)
Net income applicable to controlling interests		**203.5**		51.1
Common share dividends		**(320.4)**		(260.1)
Preferred share dividends		**(48.1)**		(41.2)
Balance, end of year	**$**	**(600.4)**	$	(435.4)
AOCI (*note 18*)				
Balance, beginning of year	**$**	**433.5**	$	163.1
Other comprehensive income (loss)		**(28.4)**		270.4
Balance, end of year	**$**	**405.1**	$	433.5
Total shareholders' equity	**$**	**4,580.6**	$	4,168.0
Non-controlling interests				
Balance, beginning of year	**$**	**34.9**	$	33.1
Net income applicable to non-controlling interests		**9.9**		8.6
Sale of interest in a subsidiary		**—**		1.8
Distribution by subsidiaries to non-controlling interests		**(10.0)**		(8.6)
Balance, end of year		**34.8**		34.9
Total equity	**$**	**4,615.4**	$	4,202.9

(1) Premium Dividend™, Dividend Reinvestment and Optional Share Purchase Plan.

See accompanying notes to the Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the year ended December 31 ($ millions)		**2016**		2015
Cash from operations				
Net income after taxes	**$**	**213.4**	$	59.7
Items not involving cash:				
Depreciation and amortization *(notes 6 and 8)*		**271.5**		211.9
Provisions on assets *(note 7)*		**—**		53.5
Accretion expenses *(notes 14 and 15)*		**11.0**		11.0
Share-based compensation *(note 20)*		**1.4**		2.8
Deferred income tax expense *(note 16)*		**8.4**		24.5
Gains on sale of assets *(notes 3 and 22)*		**(4.2)**		(0.3)
Loss (income) from equity investments *(note 11)*		**(3.4)**		63.4
Unrealized losses (gains) on risk management contracts *(note 19)*		**11.4**		(9.4)
Losses (gains) on long-term investments *(notes 10 and 22)*		**(0.5)**		34.2
Other		**2.5**		8.8
Asset retirement obligations settled *(note 14)*		**(3.8)**		(3.6)
Net distributions from equity investments		**26.0**		5.5
Changes in operating assets and liabilities *(note 27)*		**(77.5)**		39.2
	$	**456.2**	$	501.2
Investing activities				
Business acquisitions, net of cash acquired *(note 3)*		**(20.0)**		(916.0)
Acquisition of property, plant and equipment		**(507.2)**		(613.5)
Acquisition of intangible assets		**(24.4)**		(37.8)
Contributions to equity investments		**(20.2)**		(9.7)
Maturity of short-term investment		**—**		50.0
Change in restricted cash holdings from customers		**0.2**		(0.4)
Investment in Petrogas preferred shares *(note 11)*		**(150.0)**		—
Loan to affiliate *(note 26)*		**(62.5)**		—
Proceeds from disposition of assets, net of transaction costs *(note 3)*		**31.9**		9.8
Sale of interest in a subsidiary		**—**		2.0
	$	**(752.2)**	**$**	(1,515.6)
Financing activities				
Net issuance of short-term debt		**1.4**		46.5
Issuance of long-term debt, net of debt issuance costs		**674.5**		1,065.1
Repayment of long-term debt		**(884.3)**		(476.4)
Dividends - common shares		**(315.3)**		(255.8)
Dividends - preferred shares		**(49.2)**		(40.1)
Distributions to non-controlling interest		**(10.0)**		(8.6)
Net proceeds from shares issued on exercise of options		**8.5**		19.2
Net proceeds from issuance of common shares		**595.8**		384.1
Net proceeds from issuance of preferred shares		**—**		195.6
	$	**21.4**	$	929.6
Change in cash and cash equivalents		**(274.6)**		(84.8)
Effect of exchange rate changes on cash and cash equivalents		**0.2**		7.2
Cash and cash equivalents, beginning of year		**293.4**		371.0
Cash and cash equivalents, end of year	**$**	**19.0**	$	293.4

See accompanying notes to the Consolidated Financial Statements.

Notes to the Consolidated Financial Statements

(Tabular amounts and amounts in footnotes to tables are in millions of Canadian dollars unless otherwise indicated.)

1. ORGANIZATION AND OVERVIEW OF THE BUSINESS

The businesses of AltaGas are operated by AltaGas and a number of its subsidiaries including, without limitation, AltaGas Services (U.S.) Inc.; in regards to the gas business, AltaGas Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership and Harmattan Gas Processing Limited Partnership; in regards to the power business, Coast Mountain Hydro Limited Partnership, Blythe Energy Inc. (Blythe), and AltaGas San Joaquin Energy Inc.; and, in regards to the utility business, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), and SEMCO Energy, Inc. (SEMCO). SEMCO conducts its Michigan natural gas distribution business under the name SEMCO Energy Gas Company (SEMCO Gas) and its Alaska natural gas distribution business under the name ENSTAR Natural Gas Company (ENSTAR).

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 has three business segments: Gas, Power and Utilities.

AltaGas' Gas segment serves producers in the Western Canada Sedimentary Basin (WCSB) and includes natural gas gathering and processing, natural gas liquids (NGL) extraction and separation, gas transmission, gas storage and natural gas marketing, and the one-third ownership investment, through AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), in Petrogas Energy Corp. (Petrogas).

The Power segment includes 1,688 MW of gross generating capacity from natural gas-fired, wind, biomass and hydro assets in Canada and the United States, along with 20 MW of energy storage and an additional 1,253 MW of assets under development.

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

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These Consolidated Financial Statements have been prepared by management in accordance with United States Generally Accepted Accounting Principles (U.S. GAAP).

Pursuant to National Instrument 52-107, "Acceptable Accounting Principles and Auditing Standards" (NI 52-107), U.S. GAAP reporting is generally permitted by Canadian securities laws for companies subject to reporting obligations under U.S. securities laws. However, given that AltaGas is not subject to such reporting obligations and could not therefore rely on the provisions of NI 52-107 to that effect, AltaGas sought and obtained exemptive relief by the securities regulators in Alberta and Ontario to permit it to prepare its financial statements in accordance with U.S. GAAP. The exemption will terminate on or after the earlier of January 1, 2019, the date to which AltaGas ceases to have activities subject to rate regulation, or the effective date prescribed for a mandatory application of International Financial Reporting Standard for rate-regulated accounting.

PRINCIPLES OF CONSOLIDATION

These Consolidated Financial Statements of AltaGas include the accounts of the Corporation and all of its wholly-owned subsidiaries, and its interest in various partnerships and joint ventures where AltaGas has an undivided interest in the assets and liabilities of the joint venture or partnership. Investments in unconsolidated companies that AltaGas has significant influence over, but not control, are accounted for using the equity method.

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

USE OF ESTIMATES AND MEASUREMENT UNCERTAINTY

The preparation of Consolidated Financial Statements in accordance with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenue and expenses during the period. Key areas where management has made complex or subjective judgments, when matters are inherently uncertain, include but are not limited to: depreciation and amortization rates, fair value of asset retirement obligations, fair value of property, plant and equipment and goodwill for impairment assessments, fair value of financial instruments, provisions for income taxes, assumptions used to measure employee future benefits, provisions for contingencies, valuation of share-based compensation, and carrying value of regulatory assets and liabilities. Certain estimates are necessary for the regulatory environment in which AltaGas' subsidiaries or affiliates operate, which often require amounts to be recorded at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. By their nature, these estimates are subject to measurement uncertainty and may impact the Consolidated Financial Statements of future periods.

SIGNIFICANT ACCOUNTING POLICIES

Rate-Regulated Operations

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

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

Regulatory assets represent future revenues associated with certain costs incurred in the current period or in prior periods that are expected to be recovered from customers in future periods through the rate setting process. Regulatory liabilities represent future reductions or limitations of increases in revenue associated with amounts that are expected to be refunded to customers through the rate setting process.

Cash and Cash Equivalents

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

Restricted Cash Holdings from Customers

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

Short-term Investments

Short-term investments consist of investments in money market instruments with original maturities of more than three and less than 12 months. Short-term investments are carried at fair value.

Accounts Receivable

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

Inventory

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

Property, Plant, and Equipment (PP&E), Depreciation and Amortization

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

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

Interest costs are capitalized on major additions to property, plant, and equipment until the asset is ready for its intended use. The interest rate used for calculating the interest costs to be capitalized is based on AltaGas' prior quarter actual borrowing long-term interest rate.

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

The range of useful lives for AltaGas’ PP&E is as follows:

Gas assets	3 - 45 years
Power generation assets	2 - 120 years
Utilities assets	3 - 80 years
Corporate assets	1-7 years

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

Generally, when a regulated asset is retired or disposed of, there is no gain or loss recorded in the Consolidated Statement of Income. Any difference between the cost and accumulated depreciation of the asset, net of salvage proceeds, is charged to accumulated depreciation or another regulatory asset or liability account. It is expected that any gain or loss that is charged to accumulated depreciation or another regulatory account will be reflected in future depreciation expense when it is refunded or collected in rates. When a non-regulated asset is retired or disposed of from PP&E, the original cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in the Consolidated Statement of Income.

Leases are classified as either capital or operating. Leases that transfer substantially all the benefits and risks of ownership of property to AltaGas are accounted for as capital leases.

Intangible Assets

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

Energy services relationships	15 -19 years
Electricity service agreements	2 - 60 years
Software	2 - 10 years
Land rights	5 - 60 years
Franchises and consents	9 - 25 years
Extraction and Transmission (E&T) Contracts	6 - 34 years

Assets Held for Sale

The Corporation classifies assets as held for sale when the carrying amount will be recovered through a sale transaction rather than through continuing use. This condition is met when management approves and commits to a formal plan to sell the assets, the assets are available for immediate sale in their present condition, and management expects the sale to close within the next 12 months. Upon classifying an asset as held for sale, an asset is recorded at the lower of its carrying value or the estimated fair value less cost to sell. Assets held for sale are not depreciated or amortized.

Business Acquisitions

Business acquisitions are accounted for using the acquisition method. Under the acquisition method, assets and liabilities of the acquired entity are recorded at fair value at the date of acquisition. Acquisition-related costs are expensed as incurred. Goodwill represents the excess of purchase price over the fair value of the net assets acquired.

Provision on Assets

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

Goodwill is not subject to amortization, but assessed at least annually for impairment, or more often when events or changes in circumstances indicate that goodwill may be impaired. The annual assessment of goodwill is performed at the reporting unit level, which is an operating segment or one level below. The Corporation has the option to first assess qualitative factors to determine whether events or changes in circumstances indicate that the goodwill may be impaired. If a quantitative impairment test is performed, the first step of the two-step impairment test is to compare the fair value of the reporting unit to its carrying value (including goodwill). If the carrying value of the reporting unit exceeds the fair value, goodwill is reduced to its implied fair value and an impairment loss would be recorded in the Consolidated Statement of Income.

Development Costs

AltaGas expenses development costs as incurred unless such development costs meet certain criteria related to technical, market, regulatory and financial feasibility for capitalization. Development costs are examined annually to ensure capitalization criteria continue to be met. When the criteria that previously justified the deferral of costs are no longer met, the unamortized balance is taken as a charge to income in the period when this determination is made. Development costs are amortized based on the expected period of benefit, beginning at the commencement of commercial operations.

Investments Accounted for by the Equity Method

The equity method of accounting is used for investments in which AltaGas has the ability to exercise significant influence, but does not have a controlling interest. Equity investments are initially measured at cost and are adjusted for the Corporation's proportionate share of earnings or losses. Equity investments are increased for contributions made and decreased for distributions received. To the extent an investee undertakes activities necessary to commence its planned principal operations, the Corporation will capitalize interest costs associated with its investment during such period.

An equity method investment is reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment might not be recoverable. When such condition is deemed other than temporary, the carrying value of the investment is written down to its fair value, and an impairment charge is recorded in the Consolidated Statement of Income.

Financial Instruments

All financial instruments are initially recorded at fair value unless they qualify for, and are designated under, a normal purchase and normal sales (NPNS) exemption. Subsequent measurement of the financial instruments is based on their classification. The financial assets are classified as "held-for-trading", "held-to-maturity", "loans and receivables", or "available-for-sale". Financial liabilities are classified as "held-for-trading" or other financial liabilities. Subsequent measurement is determined by classification.

A physical contract generally qualifies for the NPNS exemption if the transaction is reasonable in relation to AltaGas' business needs, the counterparty owns or controls resources within the proximity to allow for physical delivery, AltaGas intends to receive physical delivery of the commodity, and AltaGas deems the counterparty creditworthy. AltaGas continually assesses the contracts designated under the NPNS exemption and will discontinue the treatment of these contracts under this exemption where the criteria are no longer met.

Held-for-trading financial assets and liabilities consist of swaps, options, forwards and equity securities. These financial instruments are initially recorded at their fair value, with subsequent changes in fair value recorded in net income under "unrealized gains and losses from risk management contracts" or "other income (loss)". Loans and receivables and other financial liabilities not classified as held-for-trading are recognized at amortized cost using the effective interest method. As at December 31, 2016 and 2015, AltaGas did not have any held-to-maturity financial assets.

The available-for-sale classification includes non-derivative financial assets that are designated as available-for-sale or are not included in the other three classifications. Available-for-sale instruments are initially recorded at fair value, and changes to fair value are recorded through "Other comprehensive income" (OCI). Declines in fair value below the amortized cost basis that are other than temporary are reclassified out of OCI to earnings for the period.

Investments in equity instruments not accounted for under the equity method that do not have a quoted market price in an active market are measured at cost. Income earned from these investments is included in the Consolidated Statement of Income under "Other income (loss)".

Derivatives embedded in other financial instruments or contracts (the host instrument) are recorded separately and are measured at fair value if the economic characteristics of the embedded derivative are not closely related to the host instrument, the terms of the embedded derivative are the same as those of a standalone derivative and the entire contract is not held-for-trading or accounted for at fair value. Changes in fair value are included in earnings.

The fair values recorded on the Consolidated Balance Sheet reflect netting of the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement.

Transaction costs related to the acquisition of held-for-trading financial assets and liabilities are expensed as incurred.

Transaction costs for obtaining debt financing other than line-of-credit arrangements are recognized as a direct deduction from the related debt liability on the Consolidated Balance Sheet. Transaction costs related to line-of-credit arrangements are capitalized and included under "Long-term investments and other assets" on the Consolidated Balance Sheet. Premiums and discounts are netted against long-term debt on the Consolidated Balance Sheets. The deferred charges are amortized over the life of the related debt on an effective interest basis and included in "Interest expense" on the Consolidated Statement of Income.

Hedges

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

The effective portion of changes in cash flow hedges is recognized in OCI. Ineffective portions and amounts excluded from effectiveness testing of hedges are included in income under “unrealized gains and losses from risk management contracts”. Gains or losses from cash flow hedges that have been included in accumulated other comprehensive income (AOCI) are reclassified to net income when the hedged transaction affects earnings, such as when the hedged forecasted transaction occurs. If the hedging instrument ceases to be effective, hedge accounting is discontinued and the cumulative gains or losses previously recognized will remain in AOCI until the forecast transaction affects earnings. If a hedged anticipated transaction is no longer probable or is sold or terminated early, the cumulative gains or losses in AOCI are immediately reclassified to earnings.

Asset Retirement Obligations

AltaGas recognizes asset retirement obligations in the period in which the legal obligation is incurred and a reasonable estimate of fair value can be determined. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and are depreciated over the estimated useful life of the asset. The liability is increased due to the passage of time over the estimated period until the settlement of the obligation, with a corresponding charge to accretion expense for asset retirement obligations.

Certain utility assets will have future legal obligations on retirement, but an asset retirement obligation has not been recorded due to its indeterminate life and corresponding indeterminable timing and scope of these asset retirement obligations. The U.S. Utilities recognize asset retirement obligations for some interim retirements, as expected by their regulators, whereas Canadian Utilities do not.

Revenue Recognition

The Utilities reporting segment recognizes revenue, presented as "revenue from regulated operations" in the Consolidated Statement of Income, when the product or services are delivered on the basis of regular meter readings or estimates of usage and is consistent with the underlying rate setting mechanism mandated by the applicable regulatory authority. The Utilities reporting segment bills gas distribution customers monthly, on a cycle basis and accrues revenue for service rendered to its customers but not billed at month-end. Storage customers are billed monthly for services provided in the preceding month and revenue is accrued for services rendered but not billed at month end.

Revenue from services represents the proceeds from operating leases in the Gas and Power reporting segments where AltaGas is the lessor, and fees from the gathering, transportation, processing, and marketing of natural gas. Revenue from services are recognized at the time the service is rendered.

Revenue from sales represents the proceeds from the commodity sales in the Gas and Power reporting segments and are recognized at the time the product is delivered.

Foreign Currency Translation

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

For foreign entities with a functional currency other than Canadian dollars, AltaGas’ reporting currency, assets, and liabilities are translated into Canadian dollars at the rate in effect at the reporting date. Revenues and expenses are translated at average exchange rates during the reporting period. All adjustments resulting from the translation of the foreign operations are recorded in OCI.

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

Share Options and Other Compensation Plans

Share options granted are recorded using fair value. Compensation expense is measured at the date of the grant using the Black-Scholes-Merton model and is recognized over the vesting period of the options. Consideration received by AltaGas on exercise of the share options is credited to shareholders' equity.

AltaGas has a medium-term incentive plan (MTIP) for employees and executive officers which includes two types of awards: restricted units (RUs) and performance units (PUs). Both RUs and PUs are valued based on the dividends declared during the vesting period and the weighted average share price of AltaGas' common shares multiplied by the units outstanding at the end of the vesting period. Upon vesting, the RUs and PUs are paid in cash or, at the election of AltaGas, its equivalent in common shares purchased from the market. The PUs are also subject to a performance multiplier ranging from 0 to 2 dependent on the Corporation's performance relative to performance targets agreed between the Corporation and the employees. Compensation expense is recognized using the liability method and is recorded as operating and administrative expense over the vesting period. A change in value of the RUs or PUs is recognized in the period the change occurs.

In addition, AltaGas has a deferred share unit plan (DSUP) for directors, officer and employees as an additional form of long-term variable compensation incentive. Although the DSUP is available to directors, officers and employees, AltaGas currently only grants deferred share units (DSUs) under the DSUP as a form of director compensation. The DSUs granted are fully vested upon being credited to a participant's account, and the participant is entitled to payment at his or her termination date, and payment is not subject to satisfaction of any requirements as to any minimum period of membership or employment or other conditions. DSUs are accounted for at fair value. Compensation expense is determined based on the fair value of the DSUs on the date of the grant and fluctuations in fair value are recognized in the period the change occurs.

Pension Plans and Post-Retirement Benefits

AltaGas maintains defined benefit pension plans, defined contribution plans, and other post-retirement benefit plans for eligible employees. Contributions made by the Corporation to the defined contribution plans are expensed in the period in which the contribution occurs.

The cost of defined benefit pension plans and post-retirement benefits is actuarially determined using the projected benefit method prorated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement ages of employees and expected health care costs. Pension plan assets are measured at fair value. The expected return on plan assets is based on historical and projected rates of return for each asset class in the plan portfolio. The projected benefit obligation is discounted using the market interest rate on high-quality debt instruments with cash flows matching the timing and amount of benefit payments.

Pension expense for the defined benefit and post-retirement benefit plans includes the cost of pension benefits earned during the year, the interest cost on pension obligations, the expected return on pension plan assets, the amortization of net transitional obligation, the amortization of adjustments arising from pension plan amendments, the amortization of prior service costs, and the amortization of the excess of the net actuarial gain or loss over 10 percent of the greater of the benefit obligation and the fair value of plan assets, which is amortized on a straight-line basis over the expected average remaining service life of active employees. The expected average remaining service period of the active members covered by the defined benefit pension plans and post-retirement benefit plans is 12.5 years and 13.6 years, respectively.

AltaGas recognizes the overfunded or underfunded status of its pension and post-retirement benefit plans as either assets or liabilities in the Consolidated Balance Sheet. Actuarial gains and losses related to changes in funded status are recognized in OCI.

For certain regulated Utilities, the Corporation expects to recover pension expense in future rates and therefore records actuarial gains and losses as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Income Taxes

Income taxes for the Corporation and its subsidiaries are calculated using the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are determined based on differences between the carrying value and the tax basis of assets and liabilities and are measured using the enacted tax rates and laws that are in effect in the periods in which the differences are expected to be settled or realized. Deferred income tax assets are routinely reviewed and a valuation allowance is recorded to reduce the deferred tax assets if it is more likely than not that deferred tax assets will not be realized. The financial statement effects of an uncertain tax position are recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxing authority. The current and deferred tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

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

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

Net Income per Share

Basic net income per common share is computed using the weighted average number of common shares outstanding during the period. Dilutive net income per common share is calculated using the weighted average number of common shares outstanding adjusted for dilutive common shares related to the Corporation’s share-based compensation awards.

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

Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation and other sources are recorded when it is probable that a liability has been incurred and the amount can be reasonably estimated. Any such accruals are adjusted thereafter as additional information becomes available or circumstances change.

ADOPTION OF NEW ACCOUNTING STANDARDS

Effective January 1, 2016, AltaGas adopted the following Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU):

- ASU No. 2014-12, “Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period”, which requires a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2015-01, "Income Statement – Extraordinary and Unusual Items", which eliminates the concept of extraordinary items. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements;

- ASU No. 2015-02, "Consolidation: Amendments to Consolidation Analysis". The amendments in this ASU affect all reporting entities that are required to evaluate whether certain legal entities should be consolidated. The amendments a) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities; b) eliminate the presumption that a general partner should consolidate a limited partnership; c) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships; and d) provide a scope exception from consolidation guidance for reporting entities with interests in certain legal entities (i.e. money market and other investment funds). The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements; and

- ASU No. 2016-17, "Consolidation: Interests Held through Related Parties That Are under Common Control". The amendment in this ASU revises the consolidation requirements that apply to a single decision maker's evaluation of interests held through related parties that are under common control. The revised guidance requires that a single decision maker report all of its direct variable interests in a VIE and, on a proportionate basis, its indirect variable interests in a VIE held through related parties, including related parties that are under common control with the reporting entity. The adoption of this ASU did not have a material impact on AltaGas' consolidated financial statements.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In July 2015, FASB issued ASU No. 2015-11 "Inventory - Simplifying the Measurement of Inventory". The amendment in this ASU requires an entity to measure inventory at the lower of cost and net realizable value. The amendments in this ASU are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, prospectively. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas' consolidated financial statements.

In May 2014, FASB issued ASU No. 2014-09 "Revenue from Contracts with Customers", which will replace numerous requirements in U.S. GAAP, including industry-specific requirements, and provide companies with a single revenue recognition model for recognizing revenue from contracts with customers. The core principle of the amendments in this ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The amendments specify various disclosure requirements that would enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. In March 2016, FASB issued ASU No. 2016-08 "Principal versus Agent Consideration". The amendments in this ASU clarify the implementation guidance on the principal versus agent considerations in the new revenue recognition standard. In April 2016, FASB issued ASU No. 2016-10 "Identifying Performance Obligation and Licensing", which reduces the complexity when applying the guidance for identifying performance obligations and improves the operability and understandability of the license implementation guidance. In May 2016, FASB issued ASU No. 2016-12 "Narrow Scope Improvements and Practical Expedients", clarifying several implementation issues, including collectability, presentation of sales taxes, non-cash consideration, contract modification, completed contracts, and transition. In December 2016, FASB issued ASU No. 2016-20 "Technical Corrections and Improvements", which makes minor technical corrections and improvements to the new revenue standard. The new revenue standard will be effective for annual and interim periods beginning on or after December 15, 2017. FASB permits adoption of the standard as early as the original effective date of December 15, 2016. Although early adoption is permitted, AltaGas will adopt ASU No. 2014-09 during the first quarter of 2018. In 2016, AltaGas established a cross-functional implementation team consisting of representatives from across all the operating segments. A preliminary scoping exercise was completed for AltaGas' operating segments and, while AltaGas is continuing to assess all potential impacts of the standard, AltaGas anticipates that the new standard will mostly impact the Gas and Utilities segments with regards to the timing of revenue recognition under the ASU for contracts that have take-or-pay features. AltaGas is still in the process of evaluating these impacts. AltaGas is currently progressing through contract reviews in order to identify and quantify potential differences. AltaGas is also awaiting further guidance from the AICPA Power and Utility

Entities Revenue Recognition Task Force related to the income statement presentation of revenue from alternative revenue programs. The ASU permits the use of either the full retrospective or modified retrospective transition method and AltaGas has yet to determine the transition method that will be applied pending the completion of the contract reviews. AltaGas expects to provide more detailed information in its 2017 financial statements as implementation progresses.

In January 2016, FASB issued ASU No. 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities” which revises an entity’s accounting related to (1) the classification and measurement of investments in equity securities and (2) the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The amendments in this ASU are effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Upon adoption, entities will be required to make a cumulative-effect adjustment to the statement of financial position as of the beginning of the first reporting period in which the guidance is effective. The guidance on equity securities without readily determinable fair value will be applied prospectively to all equity investments that exist as of the date of adoption of the standard. Upon adoption, AltaGas will no longer be able to classify equity securities with readily determinable fair values as available-for-sale and any changes in fair value will be reported through earnings instead of other comprehensive income. The remaining provisions of this ASU are not expected to have a material impact on AltaGas’ financial statements.

In February 2016, FASB issued ASU No. 2016-02 “Leases”, which requires lessees to recognize on the balance sheet a right-of-use asset and a lease liability for all leases with lease terms greater than 12 months. Lessor accounting remains substantially unchanged. The ASU also requires additional disclosures regarding leasing arrangements. The amendments in this ASU are effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. In transition, lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements but expects the new standard will have an impact on the Corporation’s balance sheet as all operating leases will need to be reflected on the balance sheet upon adoption.

In March 2016, FASB issued ASU No. 2016-05 “Derivatives and Hedging: Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships”. The amendments in this ASU apply to all entities for which there is a change in the counterparty to a derivative instrument that has been designated as a hedging instrument. This ASU clarifies that a change in the counterparty does not require de-designation of that hedging relationship. The amendments in this ASU are effective for financial statements issued for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity has an option to apply for amendments in this ASU on either a prospective basis or a modified retrospective basis. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-06 “Derivatives and Hedging: Contingent Put and Call Options in Debt Instruments”. The amendments in this ASU clarify the requirements for assessing whether contingent call (put) options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. An entity performing the assessment under the amendments in this ASU is required to assess the embedded call (put) options solely in accordance with the four-step decision sequence. The amendments in this ASU are effective for fiscal years beginning after December 15, 2016, and interim periods within those fiscal years. An entity should apply the amendment in this ASU on a modified retrospective basis, early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In March 2016, FASB issued ASU No. 2016-07 “Equity Method and Joint Ventures Investments: Simplifying the Transition to the Equity Method of Accounting”. The amendments in this ASU eliminate the requirement to retrospectively apply the equity method as a result of an increase in the level of ownership interest or degree of influence. The amendments in this ASU are effective for all entities for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. The amendments should be applied prospectively upon their effective date to increases in level of ownership interest or degree of influence. Early adoption is permitted. AltaGas will apply the amendments prospectively.

In March 2016, FASB issued ASU No. 2016-09 “Stock Compensation: Improvements to Employee Share-Based Payment Accounting”. The amendments in this ASU focus on simplifying several areas of the accounting for share-based payment transactions, including the accounting for income taxes, forfeitures, and statutory withholding requirements, as well as the classification on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2016, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In June 2016, FASB issued ASU No. 2016-13 “Financial Instruments – Credit Losses: Measurement of Credit Losses on Financial Instruments”. The amendments in this ASU replace the current “incurred loss” impairment methodology with an “expected loss” model for financial assets measured at amortized cost. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2020, and interim periods within those fiscal periods. Early adoption is permitted. AltaGas is currently assessing the impact of this ASU on its consolidated financial statements.

In August 2016, FASB issued ASU No. 2016-15 “Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments”. The amendments in this ASU clarify the classification of certain cash flow transactions on the statement of cash flow. The amendments in this ASU are effective for fiscal periods beginning after December 15, 2017, and interim periods within those fiscal periods. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In October 2016, FASB issued ASU No. 2016-16 “Income Taxes: Intra-Entity Transfers of Assets Other Than Inventory”. The amendments in this ASU revise the accounting for income tax consequences on intra-entity transfer of assets by requiring an entity to recognize current and deferred tax on intra-entity transfer of assets other than inventory when the transfer occurs. The amendment in this ASU is effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. Early adoption is also permitted but can only be adopted in the first interim period of a fiscal year. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

In November 2016, FASB issued ASU No. 2016-18 “Statement of Cash Flows: Restricted Cash”. The amendments in this ASU require those amounts deemed to be restricted cash and restricted cash equivalents to be included in the cash and cash equivalents balance on the statement of cash flows. The amendment in this update is effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU retrospectively to each period presented. Early adoption is also permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated cash flow statements.

In January 2017, FASB issued ASU No. 2017-01 “Business Combinations: Clarifying the Definition of a Business”. The amendments in this ASU change the definition of a business to assist entities with evaluating when a set of transferred assets and activities is a business. The amendments in this ASU are effective for annual periods beginning after December 15, 2017, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis on or after the effective date. AltaGas will apply the amendments prospectively.

In January 2017, FASB issued ASU No. 2017-04 “Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment”. The ASU removes Step 2 of the goodwill impairment test, eliminating the requirement to determine the fair value of individual assets and liabilities of a reporting unit to measure the goodwill impairment. An entity should adopt the amendments in this ASU for annual periods beginning after December 15, 2019, and interim periods within those annual periods. An entity should apply the amendments in this ASU on a prospective basis. Early adoption is permitted. AltaGas will apply the amendments prospectively.

3. ACQUISITIONS AND DISPOSITIONS

GWF Energy Holdings LLC (San Joaquin Facilities)

On November 30, 2015 AltaGas completed the acquisition of GWF Energy Holdings LLC, which holds a portfolio of three natural gas-fired electrical generation facilities in northern California totaling 523 MW, for $881.4 million (US$661.1 million). Subsequent to the acquisition, GWF Energy Holdings LLC and the other entities acquired were restructured, ultimately resulting in the sole successor being AltaGas San Joaquin Energy Inc. For the year ended December 31, 2016, transaction costs, such as legal, accounting, valuation and other professional fees of $1.7 million before taxes were incurred and included in the Consolidated Statement of Income, within "Operating and administrative expenses". Total transaction costs of $3.5 million before taxes have been incurred on the acquisition. The purchase price allocation representing the consideration paid and the fair value of the net assets acquired as at November 30, 2015 is complete. Below is the final purchase price allocation using an exchange rate of 1.3333 to convert U.S. dollars to Canadian dollars.

Cash consideration	$	881.4
Total consideration	$	881.4
Fair value of net assets acquired		
Current assets	$	34.8
Property, plant and equipment		576.9
Intangible assets		355.4
Current liabilities		(12.8)
Deferred income taxes		(72.9)
	$	881.4

The consolidated results for the year ended December 31, 2016 incorporate the results of operations from the San Joaquin Facilities. If the acquisition had occurred on January 1, 2015, revenues and pre-tax income would have increased by approximately $110.1 million (US$86.7 million) and $88.8 million (US$69.9 million), respectively for the year ended December 31, 2015.

Edmonton Ethane Extraction Plant (EEEP)

Effective January 1, 2016, AltaGas acquired the remaining 51 percent interest in EEEP for cash consideration of approximately $21.0 million, increasing its ownership interest to 100 percent. AltaGas accounted for the acquisition as a business combination achieved in stages and remeasured the previously held 49 percent interest in EEEP at fair value on the acquisition date using the discounted cash flow approach. The significant inputs included contracted cash flows for the facility, forecasted commodity prices, and projected operating costs based on historical pattern. No gain or loss was recorded as a result of the remeasurement. Upon the acquisition of control, AltaGas began consolidating the results of EEEP. Prior to the acquisition, AltaGas proportionately consolidated the 49 percent interest in EEEP.

Below is the final purchase price allocation:

Fair value of net assets acquired		
Property, plant and equipment	$	67.1
Asset retirement obligations		(15.0)
Deferred income taxes		(3.3)
	$	48.8

The total estimated fair value of $48.8 million included $21.0 million of cash paid to acquire the remaining 51 percent interest and $27.8 million related to the previously held interest.

The consolidated results for the year ended December 31, 2016 incorporate the results of operations from the additional ownership interest in EEEP. If the acquisition of the additional interest had occurred on January 1, 2015, changes to revenues and pre-tax income for the year ended December 31, 2015 would have been nominal.

Other Acquisitions

On January 8, 2015, AltaGas completed the acquisition of three western U.S. natural gas-fired power assets with a total generation capacity of 164 MW for cash consideration of $33.6 million (US$28.4 million). Transaction costs, such as legal, accounting, valuation, and other professional fees of US$0.8 million before taxes, were incurred and included in the Consolidated Statement of Income within "Operating and administrative expenses" for the year ended December 31, 2015.

Below is the final purchase price allocation:

Cash consideration	$	33.6
Total consideration	$	33.6
Fair value of net assets acquired		
Current assets	$	4.0
Property, plant and equipment		23.2
Intangible assets		9.2
Current liabilities		(2.8)
	$	33.6

Dispositions

On February 29, 2016, AltaGas completed the disposition of certain non-core natural gas gathering and processing assets in the Gas segment to Tidewater Midstream and Infrastructure Ltd. (Tidewater) for total gross consideration of $30.0 million in cash and approximately 43.7 million of common shares of Tidewater valued at $1.48 per share (the Tidewater Gas Asset Disposition). AltaGas accounted for its investment in Tidewater common shares using the equity method and recognized an increase of approximately $64.7 million to "Investments accounted for by the equity method" on the Consolidated Balance Sheet. The assets were located primarily in central and north central Alberta and totaled approximately 490 Mmcf/d of gross licensed natural gas processing capacity. AltaGas recognized a pre-tax gain on disposition of $4.5 million in the Consolidated Statement of Income under the line item "Other income (loss)" for the year ended December 31, 2016. In addition, AltaGas recorded a tax recovery of $10.3 million related to the asset sale for the year ended December 31, 2016.

During the year ended December 31, 2015, AltaGas disposed of its effective 25 percent interest in Boston Bar LP, which is a 7 MW run-of-river hydroelectric power generation facility on Scuzzy Creek near Boston Bar, British Columbia. In the same year, AltaGas also disposed of the 10 MW McNair run-of-river hydroelectric generating facility located on the Sunshine Coast of British Columbia, near Port Mellon, as well as 40 MW of small hydro development projects in British Columbia. The total gross proceeds from these disposals were approximately $9.2 million. A total gain of $0.4 million was recognized in the Consolidated Statement of Income under "Other income (loss)" for the year ended December 31, 2015 from the sale of these assets.

4. ASSETS HELD FOR SALE

As at		**December 31, 2016**		December 31, 2015
Assets held for sale				
Property, plant and equipment	**$**	**67.3**	$	97.7
Intangible assets		**—**		1.0
Goodwill		**3.4**		—
	$	**70.7**	$	98.7
Liabilities associated with assets held for sale				
Asset retirement obligations	**$**	**0.4**	$	8.7
	$	**0.4**	$	8.7

In 2014, Nova Chemicals Corporation provided notice that it intends to exercise its option to purchase the Ethylene Delivery Systems and the Joffre Feedstock Pipeline transmission assets in the Gas segment in March 2017. Accordingly, the related assets and liabilities were reclassified as held for sale on December 31, 2016 and were recorded at the lower of fair value less costs to sell and their carrying value.

On February 29, 2016, AltaGas completed the sale of certain non-core natural gas gathering and processing assets in the Gas segment to Tidewater that were presented as assets held for sale as at December 31, 2015. Please refer to Note 3 for further details.

5. INVENTORY

As at		**December 31, 2016**		December 31, 2015
Natural gas held in storage	**$**	**172.6**	$	166.0
Other inventory		**48.4**		38.0
	$	**221.0**	$	204.0

6. PROPERTY, PLANT AND EQUIPMENT

As at	**December 31, 2016**						December 31, 2015					
		Cost		**Accumulated amortization**		**Net book value**		Cost		Accumulated amortization		Net book value
Gas	**$**	**2,615.8**	**$**	**(630.8)**	**$**	**1,985.0**	$	2,592.1	$	(742.3)	$	1,849.8
Power		**2,957.2**		**(232.1)**		**2,725.1**		2,913.6		(150.9)		2,762.7
Utilities		**2,250.4**		**(193.5)**		**2,056.9**		2,209.3		(163.2)		2,046.1
Corporate		**65.3**		**(30.1)**		**35.2**		58.6		(21.6)		37.0
Reclassified to assets held for sale *(note 4)*		**(126.2)**		**58.9**		**(67.3)**		(222.3)		124.6		(97.7)
	$	**7,762.5**	**$**	**(1,027.6)**	**$**	**6,734.9**	$	7,551.3	$	(953.4)	$	6,597.9

Interest capitalized on long-term capital construction projects for the year ended December 31, 2016 was $10.9 million (2015 - $20.9 million).

As at December 31, 2016, the Corporation had approximately $183.4 million (December 31, 2015 - $357.2 million) of capital projects under construction that were not yet subject to amortization.

Depreciation expense related to property, plant and equipment (including assets under capital leases) for the year ended December 31, 2016 was $229.3 million (2015 - $191.7 million).

Net additions to Utilities assets at PNG and Heritage Gas are not amortized until the year after they are brought into active service as required by the respective regulatory authorities. Net additions to SEMCO's utility assets are amortized for one half year in the year in which they are brought into active service, as required by SEMCO's regulatory authority. Net additions to AUI's utility assets are amortized the month after they are brought into active service. Utility assets not yet subject to amortization were $20.9 million as at December 31, 2016 (December 31, 2015 - $43.6 million).

7. PROVISIONS ON ASSETS

Year ended December 31		**2016**		2015
Power	**$**	**—**	$	28.4
Gas		**—**		22.3
Utilities		**—**		2.8
	$	**—**	$	53.5

Power

No provisions on assets were recorded in 2016 for the Power segment. In 2015, AltaGas recorded a pre-tax provision of $28.4 million related to certain development stage wind assets in Canada and the United States.

Gas

No provisions on assets were recorded in 2016 for the Gas segment. In 2015, AltaGas recorded a pre-tax provision of $15.8 million on certain gas processing assets that were held for sale, and a pre-tax provision of $6.5 million on the DC LNG Project.

Utilities

No provisions on assets were recorded in 2016 for the Utilities segment. A pre-tax provision of $2.8 million was recorded on the assets in the Ikhil Joint Venture in 2015.

8. INTANGIBLE ASSETS

As at		**December 31, 2016**						December 31, 2015				
		Cost		**Accumulated amortization**		**Net book value**		Cost		Accumulated amortization		Net book value
E&T contracts	**$**	**53.7**	**$**	**(39.2)**	**$**	**14.5**	$	53.7	$	(37.9)	$	15.8
Electricity service agreements		**628.8**		**(37.2)**		**591.6**		642.6		(12.4)		630.2
Energy services relationships		**10.2**		**(7.4)**		**2.8**		10.3		(6.7)		3.6
Software		**118.7**		**(45.6)**		**73.1**		108.6		(33.4)		75.2
Land rights		**10.9**		**(2.2)**		**8.7**		11.8		(2.2)		9.6
Franchises and consents		**5.6**		**(2.0)**		**3.6**		3.6		(1.9)		1.7
Reclassified to assets held for sale *(note 4)*		**(27.1)**		**27.1**		**—**		(1.1)		0.1		(1.0)
	$	**800.8**	**$**	**(106.5)**	**$**	**694.3**	$	829.5	$	(94.4)	$	735.1

Amortization expense related to intangible assets for the year ended December 31, 2016 was $42.2 million (2015 - $20.2 million).

As at December 31, 2016, the Corporation excluded $8.0 million (December 31, 2015 - $6.6 million) of software assets under development as well as assets with indefinite life from the asset base subject to amortization.

The following table sets forth the estimated amortization expense of intangible assets, excluding any amortization of assets not yet subject to amortization as well as assets with indefinite life, for the years ended December 31:

2017	$	42.9
2018	$	41.0
2019	$	39.8
2020	$	35.6
2021	$	34.3
Thereafter	$	492.7

9. GOODWILL

As at	December 31, 2016	December 31, 2015
Balance, beginning of year	**$ 877.3**	$ 785.1
Provision on assets	**—**	(5.1)
Foreign exchange translation	**(17.9)**	97.3
Reclassified to assets held for sale *(note 4)*	**(3.4)**	—
Balance, end of year	**$ 856.0**	$ 877.3

10. LONG-TERM INVESTMENTS AND OTHER ASSETS

As at	December 31, 2016	December 31, 2015
Investments in publicly-traded entities	**$ 49.4**	$ 23.2
Loan to affiliate *(see note 26)*	**62.5**	—
Deferred lease receivable	**16.3**	4.6
Debt issuance costs associated with credit facilities	**5.1**	4.3
Refundable deposits	**39.0**	23.5
Loan to employee *(see note 26)*	**0.8**	0.8
Prepayment on long-term service agreements	**8.7**	7.4
Post-retirement benefit *(see note 24)*	**2.8**	—
Other	**4.7**	0.5
	$ 189.3	$ 64.3

The following table summarizes the Corporation's available-for-sale investments in equity securities:

As at	December 31, 2016	December 31, 2015
Amortized cost	**$ 21.7**	$ 21.7
Gross unrealized gains	**23.2**	—
Gross unrealized losses	**—**	(2.4)
Fair value	**$ 44.9**	$ 19.3

No other-than temporary impairment on the Corporation's available-for-sale investments was taken in 2016. In 2015, an other-than-temporary pre-tax loss of $35.4 million was re-classified from OCI and recognized in the Consolidated Statement of Income under "Other income (loss)". The recognition of the other-than-temporary loss was the result of the length of time and extent to which the market value of the shares was less than cost.

11. INVESTMENTS ACCOUNTED FOR BY THE EQUITY METHOD

Description	Location	Ownership Percentage	December 31, 2016	December 31, 2015
AltaGas Idemitsu Joint Venture LP (AIJVLP)	Canada	50	**$ 307.2**	$ 308.7
ASTC Power Partnership (ASTC) [(a)]	Canada	50	**—**	—
Craven County Wood Energy LP	United States	50	**22.9**	23.4
Eaton Rapids Gas Storage System	United States	50	**27.9**	29.0
Grayling Generating Station LP	United States	50	**30.1**	32.3
Inuvik Gas Ltd.	Canada	33.333	**—**	—
Sarnia Airport Storage Pool LP	Canada	50	**19.2**	19.9
Petrogas Preferred Shares	Canada	—	**150.0**	—
Tidewater Midstream and Infrastructure Ltd. (Tidewater)	Canada	15.4	**64.1**	—
			$ 621.4	$ 413.3

(a) ASTC was dissolved in December 2016.

Summarized combined financial information, assuming a 100 percent ownership interest in the AltaGas' equity investments listed above, is as follows:

Year ended December 31		2016		2015
Revenues	**$**	**178.6**	$	229.4
Expenses		**(147.9)**		(286.8)
	$	**30.7**	$	(57.4)

As at December 31		2016		2015
Current assets	**$**	**67.2**	$	44.1
Property, plant and equipment	**$**	**528.6**	$	102.7
Intangible assets	**$**	**28.3**	$	67.8
Long-term investments and other assets	**$**	**834.1**	$	873.1
Current liabilities	**$**	**(53.5)**	$	(63.5)
Other long-term liabilities	**$**	**(361.1)**	$	(246.6)

Petrogas Preferred Shares

AltaGas, indirectly through its investment in AIJVLP holds a one-third equity interest in Petrogas. On June 29, 2016, AltaGas, directly invested $150.0 million to subscribe for 6,000,000 cumulative redeemable convertible preferred shares of Petrogas. These preferred shares form part of AltaGas' overall investment in Petrogas and entitle AltaGas to a fixed, cumulative, preferential cash dividend at a rate of 8.5 percent per annum payable quarterly. These preferred shares are, in the normal course, redeemable at any time on or after January 1, 2018 and convertible into a specified number of common shares at the option of either holder at any time on or after April 19, 2018. For the year ended December 31, 2016, AltaGas received dividend income of $5.9 million (2015 - $nil) from the Petrogas preferred shares, which has been included in the Consolidated Statement of Income under the line item "Income (loss) from equity investments".

ASTC and the Sundance B PPAs

In the first quarter of 2016, ASTC exercised its right to terminate the Sundance B Power Purchase Arrangements for Sundance B Unit 3 and Unit 4 (collectively, the Sundance B PPAs) effective March 8, 2016 pursuant to the change in law provisions. As a result, AltaGas recognized a pre-tax provision of $4.0 million in the Consolidated Statement of Income under the line item "Income (loss) from equity investments" for the year ended December 31, 2016 on its investment in ASTC to settle the working capital deficiency.

In December 2016, AltaGas Pipeline Partnership and TransCanada Energy Ltd. dissolved the ASTC Power Partnership. On December 16, 2016, AltaGas Pipeline Partnership and the Government of Alberta reached a definitive settlement agreement regarding the termination of the Sundance B PPAs. Under the settlement agreement, AltaGas has agreed to contribute 391,879 self-generated carbon offsets and make a total of $6.0 million in cash payments payable in equal installments over three years starting in 2018. AltaGas Pipeline Partnership and ASTC were granted a full release from all past, present and future obligations respecting the Sundance B PPAs by the Government of Alberta. As a result of the settlement, AltaGas recorded an overall pre-tax termination expense of approximately $8.4 million, which includes the $6.0 million of future cash payments, the costs of the self-generated carbon offsets and associated revenue.

Tidewater

AltaGas received 43.7 million of common shares of Tidewater valued at $1.48 per share as part of the proceeds from the Tidewater Gas Asset Disposition on February 29, 2016 (see Note 3). AltaGas accounts for its investment in Tidewater common shares using the equity method. For the year ended December 31, 2016, AltaGas recognized a pre-tax dilution loss of approximately $0.7 million in the Consolidated Statement of Income under the line item "Income (loss) from equity investments" as a result of AltaGas' interest in Tidewater being diluted from 19.9 percent on February 29, 2016 to approximately 15.4 percent as at December 31, 2016.

Provisions on investments accounted for by the equity method

Other than the pre-tax provision of $4.0 million recorded on the investment in ASTC in the first quarter of 2016, no further provisions on investments accounted for by the equity method were recorded for the year ended December 31, 2016. For the year ended December 31, 2015, AltaGas recorded a pre-tax provision of $26.3 million against AltaGas' investment in ASTC in the Power segment, a pre-tax provision of $17.0 million on AltaGas' investments in its joint ventures with Idemitsu Kosan Co.,Ltd. related to the DC LNG Project in the Gas segment, and a pre-tax provision of $4.4 million on AltaGas' interest in Inuvik Gas Ltd. in the Utilities segment.

12. SHORT-TERM DEBT

As at		**December 31, 2016**		December 31, 2015
Bank indebtedness [(a)]	**$**	**6.0**	$	9.4
US$150 million operating facility [(b)]		**116.8**		117.6
$25 million operating facility [(c)]		**5.9**		3.7
	$	**128.7**	$	130.7

(a) Bank indebtedness bears interest at the lender's prime rate or at the interest rate applicable to bankers' acceptances. The prime lending rate at December 31, 2016 was 2.7 percent (December 31, 2015 – 2.7 percent).

(b) As at December 31, 2016, SEMCO held a US$150.0 million (December 31, 2015 - US$150.0 million) unsecured revolving operating credit facility with a Canadian chartered bank with a maturity date of December 20, 2021. Draws on the facility can be by way of U.S. base-rate loans, letters of credit and LIBOR loans. Letters of credit outstanding under this facility as at December 31, 2016 were $0.7 million (December 31, 2015 - $0.9 million).

(c) As at December 31, 2016, AltaGas held a $25.0 million (December 31, 2015 - $25.0 million) bank operating facility which is available for working capital purposes, has a term of 18 months and expires on May 22, 2018. Draws on the facility are by way of prime-rate advances, bankers' acceptances or letters of credit at the bank's prime rate or for a fee. Letters of credit outstanding under this facility as at December 31, 2016 were $3.9 million (December 31, 2015 - $6.1 million).

Other Credit Facilities

As at December 31, 2016, the Corporation held a $50.0 million (December 31, 2015 - $50.0 million) unsecured demand revolving operating credit facility with a Canadian chartered bank. Draws on the facility bear interest at the lender's prime rate or at the bankers' acceptance rate plus a stamping fee. Letters of credit outstanding under this facility as at December 31, 2016 were $nil (December 31, 2015 - $nil).

As at December 31, 2016, AltaGas Utility Group Inc. held a $20.0 million (December 31, 2015 - $20.0 million) unsecured, uncommitted demand operating credit facility with a Canadian chartered bank. Draws on the facility can be by way of prime rate loans, U.S. base-rate loans, letters of credit, bankers' acceptances and LIBOR loans. Letters of credit outstanding under this facility as at December 31, 2016 were $3.7 million (December 31, 2015 - $3.6 million).

As at December 31, 2016, AltaGas held a $150.0 million (December 31, 2015 – $150.0 million) unsecured four-year extendible revolving letter of credit facility. Draws on the facility can be by way of prime loans, U.S. base-rate loans, LIBOR loans, bankers' acceptances or letters of credit. Letters of credit outstanding under this facility as at December 31, 2016 were $49.1 million (December 31, 2015 – $55.8 million).

As at December 31, 2016, AltaGas held a $150.0 million (December 31, 2015 - $150.0 million) unsecured bilateral letter of credit demand facility with a Canadian chartered bank. Borrowings on the facility incur fees and interest at rates relevant to the nature of the draws made. Letters of credit outstanding under this facility as at December 31, 2016 were $104.0 million (December 31, 2015 - $80.1 million).

13. LONG-TERM DEBT

As at	Maturity date	**December 31, 2016**	December 31, 2015
Credit facilities			
$1,400 million unsecured extendible revolving[(a)]	15-Dec-2020	**$ 377.9**	$ 689.9
US$300 million unsecured extendible revolving[(b)]	8-Dec-2019	**—**	—
Medium-term notes (MTNs)			
$200 million Senior unsecured - 5.49 percent	27-Mar-2017	**200.0**	200.0
$175 million Senior unsecured - 4.60 percent	15-Jan-2018	**175.0**	175.0
$200 million Senior unsecured - 4.55 percent	17-Jan-2019	**200.0**	200.0
$200 million Senior unsecured - 4.07 percent	1-Jun-2020	**200.0**	200.0
$350 million Senior unsecured - 3.72 percent	28-Sep-2021	**350.0**	350.0
$300 million Senior unsecured - 3.57 percent	12-Jun-2023	**300.0**	300.0
$200 million Senior unsecured - 4.40 percent	15-Mar-2024	**200.0**	200.0
$300 million Senior unsecured - 3.84 percent	15-Jan-2025	**299.9**	299.9
$100 million Senior unsecured - 5.16 percent	13-Jan-2044	**100.0**	100.0
$300 million Senior unsecured - 4.50 percent	15-Aug-2044	**299.8**	299.8
$350 million Senior unsecured - 4.12 percent	7-Apr-2026	**349.8**	—
US$200 million Senior unsecured - floating[(c)]	24-Mar-2016	—	276.8
US$125 million Senior unsecured - floating[(d)]	17-Apr-2017	**167.8**	173.0
SEMCO long-term debt			
US$300 million SEMCO Senior secured - 5.15 percent[(e)]	21-Apr-2020	**402.8**	415.2
US$82 million CINGSA Senior secured - 4.48 percent[(f)]	2-Mar-2032	**97.5**	107.0
Debenture notes			
PNG RoyNat Debenture - 3.41 percent[(g)]	15-Sep-2017	**7.4**	8.6
PNG 2018 Series Debenture - 8.75 percent[(g)]	15-Nov-2018	**8.0**	9.0
PNG 2025 Series Debenture - 9.30 percent[(g)]	18-Jul-2025	**13.5**	14.0
PNG 2027 Series Debenture - 6.90 percent[(g)]	2-Dec-2027	**14.5**	15.0
Loan from Province of Nova Scotia[(h)]	31-Jul-2017	**—**	1.1
CINGSA capital lease - 3.50 percent	1-May-2040	**0.6**	0.6
CINGSA capital lease - 4.48 percent	4-Jun-2068	**0.2**	0.2
		$ 3,764.7	$ 4,035.1
Less debt issuance costs		**(14.4)**	(15.2)
		3,750.3	4,019.9
Less current portion		**(383.4)**	(287.5)
		$ 3,366.9	$ 3,732.4

(a) 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 have fees and interest at rates relevant to the nature of the draw made. On December 8, 2016, AltaGas extended the maturity of its $1.4 billion syndicated credit facility by one year to December 15, 2020.

(b) Borrowings on the facility can be by way of U.S. base rate loans, U.S. prime loans, LIBOR loans or letters of credit.

(c) The notes carried a floating rate coupon of three months LIBOR plus 0.72 percent.

(d) The notes carry a floating rate coupon of three months LIBOR plus 0.85 percent.

(e) Collateral for the US$ MTNs is certain SEMCO assets.

(f) Collateral for the CINGSA Senior secured loan is certain CINGSA assets. Alaska Storage Holding Company, LLC, a subsidiary in which AltaGas has a controlling interest, is the non-recourse guarantor of this loan.

(g) Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of PNG's property, plant and equipment, and gas purchase and gas sales contracts, and a first floating charge on other property, assets and undertakings.

(h) The loan was non-interest bearing and, if certain prescribed revenue targets were achieved, interest will immediately begin to accumulate on a prospective basis at a rate of 6 percent per annum. In July 2011, Heritage Gas elected to repay the loan in five equal installments beginning July 31, 2012. As at December 31, 2016, the loan has been fully repaid.

14. ASSET RETIREMENT OBLIGATIONS

As at		December 31, 2016		December 31, 2015
Balance, beginning of year	**$**	**67.9**	$	70.9
Obligations acquired		**11.3**		—
New obligations		**0.7**		—
Obligations settled		**(3.8)**		(3.6)
Revision in estimated cash flow		**2.1**		2.3
Accretion expense		**4.2**		4.1
Foreign exchange translation		**(0.4)**		2.9
Reclassified to liabilities associated with assets held for sale *(note 4)*		**(0.4)**		(8.7)
Balance, end of year	**$**	**81.6**	$	67.9

The majority of the asset retirement obligations are associated with gas processing facilities in the Gas segment.

AltaGas estimates the undiscounted cash required to settle the asset retirement obligations, excluding growth for inflation, at December 31, 2016 was $225.9 million (December 31, 2015 - $245.2 million).

The asset retirement obligations have been recorded in the Consolidated Financial Statements at estimated values discounted at rates between 4.0 and 8.5 percent and are expected to be incurred between 2018 and 2164. No assets have been legally restricted for settlement of the estimated liability.

In May 2014, the National Energy Board (NEB) issued a decision establishing that, by January 1, 2015, all NEB-regulated companies must have a mechanism in place for the accumulation of funds to pay for future pipeline abandonment. AltaGas Holdings Inc., a wholly-owned subsidiary of AltaGas, opted to comply with the NEB decision with a surety bond supplied by a surety company regulated by the Office of the Superintendent of Financial Institutions in the amount of $30.3 million.

15. OTHER LONG-TERM LIABILITIES

As at		December 31, 2016		December 31, 2015
Deferred lease payable	**$**	**0.7**	$	—
Deferred revenue		**4.0**		3.9
Customer advances for construction		**43.9**		46.7
NTL liability		**146.8**		151.2
Sundance B PPA termination expense [(a)]		**6.0**		—
Other long term liabilities		**4.9**		4.9
	$	**206.3**	$	206.7

(a) On December 16, 2016, AltaGas Pipeline Partnership and the Government of Alberta reached a definitive settlement agreement regarding the termination of the Sundance B PPAs. Under the settlement agreement, AltaGas has agreed to make a total of $6.0 million in cash payments in equal annual installments over three years starting in 2018.

NTL Liability

In 2010, AltaGas entered into a 60-year CPI-indexed Electricity Purchase Agreement (EPA) and other related agreements with BC Hydro for the 195-MW Forrest Kerr run-of-river hydroelectric facility. As part of the related agreements, AltaGas agreed to pay BC Hydro annual payments of approximately $11.0 million per year, adjusted for inflation, in support of the construction and operation of the Northwest Transmission Line (NTL) until 2034.

The fair value of the firm commitment on initial recognition was measured using an estimated 2 percent inflation rate and 4.27 percent discount rate. The NTL liability has been recorded within other current liabilities for $11.3 million (December 31, 2015 - $11.0 million) and other long-term liabilities for $146.8 million (December 31, 2015 - $151.2 million) as at December 31, 2016. Accretion expense for the year ended December 31, 2016 was $6.8 million (2015 - $6.9 million). The initial consideration and the fair value of the future consideration of $258.5 million has been recognized within intangible assets and is being depreciated over 60 years, the term of the EPA with BC Hydro.

16. INCOME TAXES

Year ended December 31		**2016**		2015
Income before income taxes - consolidated	**$**	**246.2**	$	108.0
Statutory income tax rate (%)		**27.0**		26.0
Expected taxes at statutory rates	**$**	**66.5**	$	28.1
Add (deduct) the tax effect of:				
Rate adjustments to enacted Canadian rates		**(8.8)**		(6.1)
Permanent differences between accounting and tax basis of assets and liabilities		**(1.9)**		2.0
Non-taxable portion of capital losses on disposition of assets and investments		**(1.3)**		4.8
Non-taxable portion of recorded equity income		**(1.6)**		(1.8)
Impact of state taxes		**8.5**		0.3
Rate adjustment for change in the Alberta tax rate		**—**		13.8
Tax on preferred shares		**1.5**		1.1
Financing fees		**(4.5)**		(4.2)
Tax differences on divestitures and transactions		**(15.1)**		—
Change in valuation allowance		**(4.8)**		16.0
Change in uncertain tax positions		**(1.5)**		—
Other		**1.7**		3.9
Deferred income tax recovery on regulated assets		**(5.7)**		(5.0)
Prior year adjustment		**(0.2)**		(4.6)
	$	**32.8**	$	48.3
Income tax provision				
Current				
Canada		**10.0**		15.6
United States		**14.4**		8.2
	$	**24.4**	$	23.8
Deferred				
Canada		**(28.7)**		6.7
United States		**37.1**		17.8
	$	**8.4**	$	24.5
Effective income tax rate (%)		**13.3**		44.7

Effective July 1, 2015, the Alberta corporate tax rate increased from 10 percent to 12 percent. As a result of the revaluation of the deferred income tax liabilities using the increased tax rate, AltaGas recognized an additional $13.8 million of deferred income tax expense for the year ended December 31, 2015.

Net deferred income tax liabilities were composed of the following:

As at		**December 31, 2016**		December 31, 2015
PP&E and intangible assets	**$**	**737.0**	$	612.6
Regulatory assets		**37.3**		168.6
Deferred financing		**20.0**		(12.9)
Deferred compensation		**(15.0)**		(14.3)
Non-capital losses		**(213.2)**		(165.9)
Valuation allowance		**43.9**		17.7
Other		**8.9**		11.4
	$	**618.9**	$	617.2

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

As at December 31, 2016 the Corporation had tax-affected non-capital losses of approximately $213 million for tax purposes, which will be available to offset future taxable income. If not used, these losses will expire between 2023 and 2036.

Uncertain Tax Positions

On an annual basis the Corporation and its subsidiaries file tax returns in Canada and various foreign jurisdictions. In Canada AltaGas' federal and provincial tax returns for the years 2009 to 2015 remain subject to examination by taxation authorities. In the United States both the federal and state tax returns filed for the years 2011 to 2015 remain subject to examination by the taxation authorities.

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

Year ended December 31		**2016**		2015
Balance, beginning of year	**$**	**3.7**	$	3.7
Net changes during the year		**(1.5)**		—
Balance, end of year	**$**	**2.2**	$	3.7

17. REGULATORY ASSETS AND LIABILITIES

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

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

The following table summarizes the regulatory assets and liabilities recorded in the Consolidated Balance Sheets, as well as the remaining period, as of December 31, 2016 and 2015, over which the Corporation expects to realize or settle the assets or liabilities:

As at		December 31, 2016		December 31, 2015	Recovery Period
Regulatory assets - current					
Deferred cost of gas	**$**	**0.8**	$	3.7	Less than one year
Deferred property taxes		**0.1**		0.6	Less than one year
	$	**0.9**	$	4.3	
Regulatory assets - non-current					
Deferred regulatory costs and rate stabilization adjustment mechanism	**$**	**18.0**	$	19.0	1 - 3 years
Pipeline rehabilitation costs		**6.7**		6.8	Various
Future recovery of pension and other retirement benefits [a]		**114.7**		130.3	Various
Deferred environmental costs		**18.0**		22.3	1-10 years
Deferred loss on reacquired debt		**3.4**		4.3	1-15 years
Deferred depreciation and amortization [b]		**24.0**		22.9	Various
Deferred future income taxes [c]		**104.7**		96.4	Various
Deferred customer retention program amortization [d]		**6.4**		—	Various
Revenue deficiency account [e]		**29.2**		29.3	Various
Other		**4.0**		2.0	Various
	$	**329.1**	$	333.3	
Regulatory liabilities - current					
Deferred cost of gas	**$**	**13.7**	$	15.1	Less than one year
Energy optimization costs		**0.6**		3.0	Less than one year
Interruptible storage service revenue		**0.3**		1.1	Less than one year
Refundable tax credit [f]		**2.0**		2.1	Less than one year
	$	**16.6**	$	21.3	
Regulatory liabilities - non-current					
Option fees deferral [g]	**$**	**4.1**	$	3.7	Various
Refundable tax credit [f]		**10.1**		12.5	5 years
Future removal and site restoration costs [h]		**154.9**		150.3	3-56 years
Insurance recovery of environmental costs		**0.5**		0.8	2 years
Interruptible storage service revenue		**—**		0.3	2 years
Other		**0.9**		—	Various
	$	**170.5**	$	167.6	

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

(b) Pursuant to the NSUARB decisions in 2009 and 2011, Heritage Gas was ordered to suspend amortization of property, plant and equipment and intangible assets for regulatory purposes for the fiscal periods from 2009 to 2013. The NSUARB, in its decision dated November 24, 2011, directed amortization to be phased in over a four year period at the following rates: 2014 at 25 percent of the authorized rates; 2015 at 50 percent of the authorized rates; 2016 at 75 percent of the authorized rates; and 2017 at 100 percent of the authorized rates. As a result of this order, the Heritage Gas recognizes a regulatory asset equal to the amortization that would have otherwise been included in rates.

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

(d) 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.

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

(f) On September 18, 2013, CINGSA received a US$15.0 million gas storage facility tax credit from the State of Alaska for the benefit of its firm storage service customers. CINGSA will derive no direct or indirect benefit from the tax credit. Following receipt of the tax credit, CINGSA deposited it in a separate interest-bearing account. CINGSA will act as a custodian of the tax credit and any interest earned for the benefit of CINGSA's customers. On an annual basis, covering the years 2012 through 2021, CINGSA will disburse to the customers 1/10th of the amount of the tax credit not subject to refund to the State and interest earned. The RCA has approved the disbursement methodology.

(g) Pursuant to BCUC approved negotiated settlement agreement.

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

18. ACCUMULATED OTHER COMPREHENSIVE INCOME

($ millions)	Available-for-sale	Cash flow hedges	Defined benefit pension and PRB plans	Hedge net investments	Translation foreign operations	Equity Investee	Total
Opening balance, January 1, 2016	**$ (2.4)**	**$ —**	**$ (9.6)**	**$ (169.6)**	**$ 610.5**	**$ 4.6**	**$ 433.5**
OCI before reclassification	**25.6**	**—**	**(3.4)**	**44.6**	**(84.2)**	**1.3**	**(16.1)**
Amounts reclassified from OCI	**—**	**—**	**1.0**	**—**	**—**	**—**	**1.0**
Current period OCI (pre-tax)	**25.6**	**—**	**(2.4)**	**44.6**	**(84.2)**	**1.3**	**(15.1)**
Income tax on amounts retained in AOCI	**(3.4)**	**—**	**1.0**	**(10.6)**	**—**	**—**	**(13.0)**
Income tax on amounts reclassified to earnings	**—**	**—**	**(0.3)**	**—**	**—**	**—**	**(0.3)**
Net current period OCI	**22.2**	**—**	**(1.7)**	**34.0**	**(84.2)**	**1.3**	**(28.4)**
Ending balance, December 31, 2016	**$ 19.8**	**$ —**	**$ (11.3)**	**$ (135.6)**	**$ 526.3**	**$ 5.9**	**$ 405.1**
Opening balance, January 1, 2015	$ (12.0)	$ 13.3	$ (9.6)	$ (70.9)	$ 242.3	$ —	$ 163.1
OCI before reclassification	(24.2)	(0.4)	(1.4)	(99.1)	368.2	4.6	247.7
Amounts reclassified from OCI	35.4	(17.5)	0.9	—	—	—	18.8
Current period OCI (pre-tax)	11.2	(17.9)	(0.5)	(99.1)	368.2	4.6	266.5
Income tax on amounts retained in AOCI	(0.1)	0.2	0.8	0.4	—	—	1.3
Income tax on amounts reclassified to earnings	(1.5)	4.4	(0.3)	—	—	—	2.6
Net current period OCI	9.6	(13.3)	—	(98.7)	368.2	4.6	270.4
Ending balance, December 31, 2015	$ (2.4)	$ —	$ (9.6)	$ (169.6)	$ 610.5	$ 4.6	$ 433.5

Reclassification From Accumulated Other Comprehensive Income

		For the year ended December 31	
AOCI components reclassified	Income statement line item	**2016**	2015
Cash flow hedges - commodity contracts			
Commodity contracts - NGL (realized effective portion)	Service revenue	**$ —**	$ (7.2)
Commodity contracts - NGL (discontinuation of hedge accounting)	Unrealized gains on risk management contracts	**—**	(10.3)
Available-for-sale	Other income (loss)	**—**	35.4
Defined benefit pension and PRB plans	Operating and administrative expense	**$ 1.0**	$ 0.9
	Total before income taxes	**1.0**	18.8
Deferred income taxes	Income tax expenses – deferred	**(0.3)**	2.6
		$ 0.7	$ 21.4

19. FINANCIAL INSTRUMENTS AND FINANCIAL RISK MANAGEMENT

The Corporation’s financial instruments consist of cash and cash equivalents, accounts receivable, risk management contracts, certain long-term investments and other assets, accounts payable and accrued liabilities, dividends payable, short-term and long-term debt and certain other current and long-term liabilities.

Fair Value Hierarchy

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

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

Level 2 - fair values are determined based on valuation models and techniques where inputs other than quoted prices included within level 1 are observable for the asset or liability either directly or indirectly. AltaGas uses over-the-counter derivative instruments to manage fluctuations in commodity prices and foreign exchange rates. AltaGas estimates forward prices based on published sources adjusted for factors specific to the asset or liability, including basis and location differentials, discount rates, and currency exchange. The forward curves used to mark-to-market these derivative instruments are vetted against public sources.

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

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

Cash and cash equivalents, Accounts receivable, Accounts payable, Short-term debt and Dividends payable - the carrying amounts approximate fair value because of the short maturity of these instruments.

Current portion of long-term debt, Long-term debt and Other long-term liabilities - the fair value of these liabilities has been estimated based on discounted future interest and principal payments using the current market interest rates of instruments with similar terms.

Risk management assets and liabilities - the fair values of power, natural gas and NGL derivative contracts were calculated using discounted cash flow analysis based upon forward prices from published sources for the relevant period. The fair value of foreign exchange derivative contracts was calculated using quoted market rates.

	December 31, 2016				
	Carrying Amount	**Level 1**	**Level 2**	**Level 3**	**Total Fair Value**
Financial assets					
Cash and cash equivalents	**$ 19.0**	**$ 19.0**	**$ —**	**$ —**	**$ 19.0**
Risk management assets - current	**40.4**	**—**	**40.4**	**—**	**40.4**
Risk management assets - non-current	**24.1**	**—**	**24.1**	**—**	**24.1**
Long-term investments and other assets (a)	**113.0**	**49.4**	**63.6**	**—**	**113.0**
	$ 196.5	**$ 68.4**	**$ 128.1**	**$ —**	**$ 196.5**
Financial liabilities					
Risk management liabilities - current	**$ 32.9**	**$ —**	**$ 32.9**	**$ —**	**$ 32.9**
Risk management liabilities - non-current	**12.6**	**—**	**12.6**	**—**	**12.6**
Current portion of long-term debt	**383.4**	**—**	**385.3**	**—**	**385.3**
Long-term debt	**3,366.9**	**—**	**3,500.9**	**—**	**3,500.9**
Other current liabilities (b)	**22.3**	**—**	**22.0**	**—**	**22.0**
Other long-term liabilities (b)	**152.8**	**—**	**152.4**	**—**	**152.4**
	$ 3,970.9	**$ —**	**$ 4,106.1**	**$ —**	**$ 4,106.1**

(a) Excludes non-financial assets.

(b) Excludes non-financial liabilities.

	December 31, 2015				
	Carrying Amount	Level 1	Level 2	Level 3	Total Fair Value
Financial assets					
Cash and cash equivalents	$ 293.4	$ 293.4	$ —	$ —	$ 293.4
Risk management assets - current	50.4	—	50.4	—	50.4
Risk management assets - non-current	23.5	—	23.5	—	23.5
Long-term investments and other assets [(a)]	24.0	24.0	—	—	24.0
	$ 391.3	$ 317.4	$ 73.9	$ —	$ 391.3
Financial liabilities					
Risk management liabilities - current	$ 33.5	$ —	$ 33.5	—	$ 33.5
Risk management liabilities - non-current	15.7	—	15.7	—	15.7
Current portion of long-term debt	287.5	—	286.2	—	286.2
Long-term debt	3,732.4	—	3,787.5	—	3,787.5
Other current liabilities [(b)]	11.0	—	11.0	—	11.0
Other long-term liabilities [(b)]	151.2	—	144.9	—	144.9
	$ 4,231.3	$ —	$ 4,278.8	$ —	$ 4,278.8

(a) Excludes non-financial assets.

(b) Excludes non-financial liabilities.

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

For the year ended December 31	**2016**	2015
Natural gas	**$ 0.2**	$ 7.2
Storage optimization	**(5.3)**	(0.4)
NGL frac spread	**(12.2)**	(3.2)
Power	**4.7**	6.3
Heat rate	**(0.1)**	(0.3)
Foreign exchange	**1.0**	(0.1)
Embedded derivative	**0.3**	(0.1)
	$ (11.4)	$ 9.4

Offsetting of Derivative Assets and Derivative Liabilities

Certain AltaGas risk management contracts are subject to master netting arrangements that create a legally enforceable right to offset by counterparty the related financial assets and financial liabilities.

	December 31, 2016		
Risk management assets (a)	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Net amounts presented in balance sheet
Natural gas	$ 20.1	$ (2.9)	$ 17.2
Storage optimization	0.7	(0.7)	—
NGL frac spread	3.4	—	3.4
Power	43.5	—	43.5
Foreign exchange	1.8	(1.4)	0.4
	$ 69.5	$ (5.0)	$ 64.5
Risk management liabilities (b)			
Natural gas	$ 16.5	$ (2.9)	$ 13.6
Storage optimization	3.5	(0.7)	2.8
NGL frac spread	15.7	—	15.7
Power	13.4	—	13.4
Foreign exchange	1.4	(1.4)	—
	$ 50.5	$ (5.0)	$ 45.5

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $40.4 million and risk management assets (non-current) balance of $24.1 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $32.9 million and risk management liabilities (non-current) balance of $12.6 million.

	December 31, 2015		
Risk management assets (a)	Gross amounts of recognized assets/liabilities	Gross amounts offset in balance sheet	Net amounts presented in balance sheet
Natural gas	$ 40.1	$ (1.9)	$ 38.2
Storage optimization	3.0	(0.5)	2.5
Power	34.0	(0.9)	33.1
Heat rate	0.1	—	0.1
Foreign exchange	2.2	(2.2)	—
	$ 79.4	$ (5.5)	$ 73.9
Risk management liabilities (b)			
Natural gas	$ 37.0	$ (1.9)	$ 35.1
Storage optimization	0.5	(0.5)	—
Power	14.5	(0.9)	13.6
Foreign exchange	2.7	(2.2)	0.5
	$ 54.7	$ (5.5)	$ 49.2

(a) Net amount of risk management assets on the Balance Sheet is comprised of risk management assets (current) balance of $50.4 million and risk management assets (non-current) balance of $23.5 million.

(b) Net amount of risk management liabilities on the Balance Sheet is comprised of risk management liabilities (current) balance of $33.5 million and risk management liabilities (non-current) balance of $15.7 million.

Risks associated with financial instruments

AltaGas is exposed to various financial risks in the normal course of operations such as market risks resulting from fluctuations in commodity prices, currency exchange rates and interest rates as well as credit risk and liquidity risk.

Commodity Price Risk

AltaGas enters into financial derivative contracts to manage exposure to fluctuations in commodity prices. The use of derivative instruments is governed under formal risk management policies and is subject to parameters set out by AltaGas' Risk Management Committee and Board of Directors. AltaGas does not make use of derivative instruments for speculative purposes.

Natural Gas

AltaGas purchases and sells natural gas to its customers. The fixed price and market price contracts for both the purchase and sale of natural gas extend to 2021. AltaGas had the following contracts and commodity swaps outstanding related to the storage optimization activities as at December 31, 2016 and 2015:

December 31, 2016	**Fixed price (per GJ)**	**Period (months)**	**Notional volume (GJ)**	**Fair Value ($ millions)**
Sales	**1.96 to 8.46**	**1-60**	**63,209,420**	**6.6**
Purchases	**1.94 to 6.50**	**1-60**	**58,913,082**	**(4.4)**
Swaps	**8.78 to 9.91**	**1-3**	**474,037**	**1.4**

December 31, 2015	Fixed price (per GJ)	Period (months)	Notional volume (GJ)	Fair Value ($ millions)
Sales	1.40 to 5.25	1-60	95,526,580	25.2
Purchases	1.37 to 5.20	1-60	81,949,419	(22.1)
Swaps	2.58 to 3.02	1-3	3,372,837	—

NGL Frac Spread

AltaGas entered into a series of swaps to lock in a portion of the volumes exposed to NGL frac spread. AltaGas had the following contracts outstanding as at December 31, 2016 (December 31, 2015 – no outstanding contracts):

December 31, 2016	**Fixed price**	**Period (months)**	**Notional volume**	**Fair Value**
Propane swaps	**$25.51 to $29.92 /Bbl**	**1-12**	**1,330,063 Bbl**	**(12.5)**
Butane swaps	**$29.88 /Bbl**	**1-3**	**49,500 Bbl**	**(1.0)**
Crude oil swaps	**$56.40 to $70.75 /Bbl**	**1-12**	**302,710 Bbl**	**(2.2)**
Natural gas swaps	**$2.23 to $2.88/GJ**	**1-12**	**7,639,175 GJ**	**3.4**

Power

AltaGas sells power to the Alberta Electric System Operator at market prices as well as to commercial and industrial users in Alberta at fixed prices. AltaGas' strategy is to mitigate the cash flow risk to Alberta power prices to provide predictable earnings. Therefore, AltaGas uses third party swaps and purchase contracts to fix the prices over time on a portion of the volumes to mitigate financial exposure associated with the sale contracts. These power purchase and sale contracts extend to 2021. As at December 31, 2016, AltaGas had no intention to terminate any contracts prior to maturity. AltaGas had the following commodity forward contracts on power, commodity swaps, and heat rate hedges outstanding as at December 31, 2016 and 2015:

December 31, 2016	Fixed price (per MWh)	Period (months)	Notional volume (MWh)	Fair Value ($ millions)
Power sales	**34.00 to 99.25**	**1-60**	**2,671,748**	**36.2**
Power purchases	**52.68 to 69.72**	**1-24**	**217,520**	**0.5**
Swap purchases	**30.00 to 58.50**	**1-60**	**1,472,040**	**(6.6)**

December 31, 2015	Fixed price (per GJ or MWh)	Period (months)	Notional volume (GJ or MWh)	Fair Value ($ millions)
Power sales	35.94 to 99.25	1-60	2,834,736	24.5
Power purchases	52.50 to 69.72	1-36	478,112	(8.6)
Swap sales	31.00 to 44.00	1-12	256,800	2.0
Swap purchases	37.00 to 56.50	1-48	490,752	1.6
Heat rate electricity sales	43.55 to 49.35	1	4,960	0.1

The table below provides the potential impact on pre-tax income due to changes in the fair value of risk management contracts in place as at December 31, 2016:

Factor	Increase or decrease to forward prices	Increase or decrease to income before tax ($ millions)
Alberta power price	$1/MWh	1.0
AECO natural gas price	$0.50/GJ	0.1
NGL frac spread:		
Propane	$1/Bbl	1.3
Butane	$1/Bbl	0.1
Western Texas Intermediate (WTI) crude oil	$1/Bbl	0.3
Natural gas	$0.50/GJ	3.8

Foreign Exchange Risk

AltaGas is exposed to foreign exchange risk as changes in foreign exchange rates may affect the fair value or future cash flows of the Corporation's financial instruments. AltaGas has foreign operations whereby the functional currency is the U.S. dollar. As a result, the Corporation's earnings, cash flows, and OCI are exposed to fluctuations resulting from changes in foreign exchange rates. This risk is partially mitigated by AltaGas' U.S. dollar-denominated debt and preferred shares. AltaGas may also enter into foreign exchange forward derivatives to manage the risk of fluctuating cash flows due to variations in foreign exchange rates. As at December 31, 2016, AltaGas had outstanding foreign exchange forward contracts for US$5.1 million at an average rate of $1.26 Canadian per U.S. dollar which are expected to be settled over the next four months.

AltaGas also designates its U.S. dollar-denominated debt as a net investment hedge of its U.S. subsidiaries. As at December 31, 2016, AltaGas designated US$301.0 million of outstanding debt as a net investment hedge (December 31, 2015 - US$723.5 million). For the year ended December 31, 2016, AltaGas incurred an after-tax unrealized gain of $34.0 million arising from the translation of debt in OCI (2015 - after-tax unrealized loss of $98.7 million).

Interest Rate Risk

AltaGas is exposed to interest rate risk as changes in interest rates may impact future cash flows and the fair value of its financial instruments. The Corporation manages its interest rate risk by holding a mix of both fixed and floating interest rate debt. As at December 31, 2016, approximately 83 percent of AltaGas' total outstanding short-term and long-term debt was at fixed rates. In addition, from time to time, AltaGas may enter into interest rate swap agreements to fix the interest rate on a portion of its banker's acceptances issued under its credit facilities. There were no outstanding interest rate swaps as at December 31, 2016.

Credit Risk

Credit risk results from the possibility that a counterparty to a financial instrument fails to fulfill its obligations in accordance with the terms of the contract.

AltaGas' credit policy details the parameters used to grant, measure, monitor and report on credit provided to counterparties. AltaGas minimizes counterparty risk by conducting credit reviews on counterparties in order to establish specific credit limits, both prior to providing products or services and on a recurring basis. In addition, most contracts include credit mitigation clauses that allow AltaGas to obtain financial or performance assurances from counterparties under certain circumstances. AltaGas maintains an allowance for doubtful accounts in the normal course of its business.

AltaGas' maximum credit exposure consists primarily of the carrying value of the non-derivative financial assets and the fair value of derivative financial assets. As at December 31, 2016, AltaGas had no concentration of credit risk with a single counterparty.

Accounts Receivable Past Due or Impaired

AltaGas had the following past due or impaired accounts receivable (AR):

As at December 31, 2016	**Total**	**AR accruals**	**Receivables impaired**	**Less than 30 days**	**31 to 60 days**	**61 to 90 days**	**Over 90 days**
Trade receivable	**$ 339.1**	**$ 160.4**	**$ 2.5**	**$ 166.1**	**$ 6.4**	**$ 2.4**	**$ 1.3**
Other	**2.2**	**—**	**—**	**2.2**	**—**	**—**	**—**
Allowance for credit losses	**(2.5)**	**—**	**(2.5)**	**—**	**—**	**—**	**—**
	$ 338.8	**$ 160.4**	**$ —**	**$ 168.3**	**$ 6.4**	**$ 2.4**	**$ 1.3**

As at December 31, 2015	Total	AR accruals	Receivables impaired	Less than 30 days	31 to 60 days	61 to 90 days	Over 90 days
Trade receivable	$ 323.3	$ 122.7	$ 2.7	$ 187.3	$ 6.4	$ 1.2	$ 3.0
Other	12.7	—	—	12.5	0.1	—	0.1
Allowance for credit losses	(2.7)	—	(2.7)	—	—	—	—
	$ 333.3	$ 122.7	$ —	$ 199.8	$ 6.5	$ 1.2	$ 3.1

Allowance for credit losses	**December 31, 2016**	December 31, 2015
Balance, beginning of year	**$ 2.7**	$ 2.5
Foreign exchange translation	**—**	0.3
New allowance	**0.4**	0.1
Allowance applied to uncollectible customer accounts	**(0.6)**	(0.2)
Balance, end of year	**$ 2.5**	$ 2.7

Liquidity Risk

Liquidity risk is the risk that AltaGas will not be able to meet its financial obligations as they come due. AltaGas manages this risk through its extensive budgeting and monitoring process to ensure it has sufficient cash and credit facilities to meet its obligations. AltaGas' objective is to maintain its investment-grade ratings to ensure it has access to debt and equity funding as required.

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

			Payments due by period							
As at December 31, 2016		**Total**		**Less than 1 year**		**1-3 years**		**4-5 years**		**After 5 years**
Accounts payable and accrued liabilities	**$**	**345.8**	**$**	**345.8**	**$**	**—**	**$**	**—**	**$**	**—**
Dividends payable		**29.2**		**29.2**		**—**		**—**		**—**
Short-term debt		**128.7**		**128.7**		**—**		**—**		**—**
Other current liabilities (a)		**22.3**		**22.3**		**—**		**—**		**—**
Other long-term liabilities (a)		**152.8**		**—**		**25.2**		**22.4**		**105.2**
Risk management contract liabilities		**45.5**		**32.9**		**9.1**		**3.5**		**—**
Current portion of long-term debt (b)		**383.5**		**383.5**		**—**		**—**		**—**
Long-term debt (b)		**3,381.2**		**—**		**396.6**		**1,345.2**		**1,639.4**
	$	**4,489.0**	**$**	**942.4**	**$**	**430.9**	**$**	**1,371.1**	**$**	**1,744.6**

(a) Excludes non-financial liabilities

(b) Excludes deferred financing costs

			Payments due by period							
As at December 31, 2015		Total		Less than 1 year		1-3 years		4-5 years		After 5 years
Accounts payable and accrued liabilities	$	383.1	$	383.1	$	—	$	—	$	—
Dividends payable		24.1		24.1		—		—		—
Short-term debt		130.7		130.7		—		—		—
Other current liabilities (a)		11.0		11.0		—		—		—
Other long-term liabilities (a)		151.2		—		20.7		20.0		110.5
Risk management contract liabilities		49.2		33.5		12.4		3.3		—
Current portion of long-term debt (b)		287.6		287.6		—		—		—
Long-term debt (b)		3,747.5		—		578.1		1,520.3		1,649.1
	$	4,784.4	$	870.0	$	611.2	$	1,543.6	$	1,759.6

(a) Excludes non-financial liabilities

(b) Excludes deferred financing costs

20. SHAREHOLDERS' EQUITY

Authorization

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

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 $440.6 million.

On September 30, 2015, AltaGas closed a public offering of 8,760,000 common shares, at an issue price of $34.25 per common share for aggregate gross proceeds of approximately $300.0 million.

Premium Dividend™, Dividend Reinvestment and Optional Cash Purchase Plan (DRIP or the 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 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

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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 are 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.

Common Shares Issued and Outstanding	Number of shares		Amount
January 1, 2015	133,941,749	$	2,759.9
Shares issued on public offering, net of issuance costs	8,760,000		287.9
Shares issued for cash on exercise of options	834,268		20.8
Deferred taxes on share issuance cost	—		3.3
Shares issued under DRIP	2,745,230		96.2
December 31, 2015	146,281,247		3,168.1
Shares issued on public offering, net of issuance costs	14,685,000		422.2
Shares issued for cash on exercise of options	337,750		9.3
Deferred taxes on share issuance costs	—		0.2
Shares issued under DRIP	5,602,836		173.6
Issued and outstanding at December 31, 2016	**166,906,833**	**$**	**3,773.4**

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Preferred Shares

Preferred Shares Series A Issued and Outstanding	Number of shares		Amount
January 1, 2015	8,000,000	$	195.9
Shares converted to Series B	(2,488,780)		(60.9)
December 31, 2015	5,511,220		135.0
Issued and outstanding at December 31, 2016	**5,511,220**	**$**	**135.0**

Preferred Shares Series B Issued and Outstanding	Number of shares		Amount
January 1, 2015	—	$	—
Shares issued on conversion from Series A	2,488,780		60.9
December 31, 2015	2,488,780		60.9
Issued and outstanding at December 31, 2016	**2,488,780**	**$**	**60.9**

Preferred Shares Series C Issued and Outstanding	Number of shares		Amount
January 1, 2015	8,000,000	$	200.6
December 31, 2015	8,000,000		200.6
Issued and outstanding at December 31, 2016	**8,000,000**	**$**	**200.6**

Preferred Shares Series E Issued and Outstanding	Number of shares		Amount
January 1, 2015	8,000,000	$	195.8
December 31, 2015	8,000,000		195.8
Issued and outstanding at December 31, 2016	**8,000,000**	**$**	**195.8**

Preferred Shares Series G Issued and Outstanding	Number of shares		Amount
January 1, 2015	8,000,000	$	196.1
December 31, 2015	8,000,000		196.1
Issued and outstanding at December 31, 2016	**8,000,000**	**$**	**196.1**

Preferred Shares Series I Issued and Outstanding	Number of shares		Amount
January 1, 2015	—	$	—
Shares issued	8,000,000		200.0
Share issuance costs, net of taxes	—		(3.3)
December 31, 2015	8,000,000		196.7
Issued and outstanding at December 31, 2016	**8,000,000**	**$**	**196.7**

The following table outlines the characteristics of the cumulative redeemable preferred shares [(a)]:

	Current Yield	Annual dividend per share[(b)]	Redemption price per share	Redemption and conversion option date[(c)(d)]	Right to convert into[(d)]
Series A [(e)]	3.38%	$0.845	$25	September 30, 2020	Series B
Series B [(f)]	Floating [(f)]	Floating [(f)]	$25	September 30, 2020 [(g)]	Series A
Series C [(h)]	4.40%	US$1.10	US$25	September 30, 2017	Series D
Series E [(e)]	5.00%	$1.25	$25	December 31, 2018	Series F
Series G [(e)]	4.75%	$1.1875	$25	September 30, 2019	Series H
Series I [(i)]	5.25%	$1.3125	$25	December 31, 2020	Series J

(a) 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, Series F, Series H, and Series J, 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, Series F, Series H, and Series J 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.

(b) The holders of Series A, C, E, G, and I are entitled to receive a cumulative quarterly fixed dividend as and when declared by the Board of Directors. The holders of Series B 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, Series F, Series H and Series J will be entitled to receive a quarterly floating dividend as and when declared by the Board of Directors.

(c) 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.

(d) 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.

(e) 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), 3.17 percent (Series E), and 3.06 percent (Series G).

(f) Holders of Series B 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 is $0.19541 per Series B preferred share for the period starting December 31, 2016 to, but excluding, March 31, 2017.

(g) Series B 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.

(h) Holders of Series C 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.

(i) 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.

Share Option Plan

AltaGas has an employee share option plan under which employees and directors are eligible to receive grants. As at December 31, 2016, 12,571,297 shares were reserved for issuance under the plan. As at December 31, 2016, options granted under the plan have a term between six and ten years until expiry and vest no longer than over a four-year period.

As at December 31, 2016, unexpensed fair value of share option compensation cost associated with future periods was $1.0 million (December 31, 2015 - $2.7 million).

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

As at	**December 31, 2016**			December 31, 2015		
	Options outstanding			Options outstanding		
	Number of options		**Exercise price[(a)]**	Number of options		Exercise price[(a)]
Share options outstanding, beginning of year	**4,559,261**	**$**	**32.02**	5,123,655	$	30.28
Granted	**89,500**		**31.45**	470,000		36.94
Exercised	**(337,750)**		**25.28**	(834,268)		22.93
Expired	**(92,249)**		**34.35**	(19,125)		41.67
Forfeited	**(99,376)**		**36.77**	(181,001)		36.88
Share options outstanding, end of year	**4,119,386**	**$**	**32.39**	4,559,261	$	32.02
Share options exercisable, end of year	**3,279,133**	**$**	**30.56**	3,009,946	$	28.71

(a) Weighted average.

As at December 31, 2016, the aggregate intrinsic value of the total options exercisable was $16.5 million (December 31, 2015 - $12.0 million), the total intrinsic value of options outstanding was $16.8 million (December 31, 2015 - $12.2 million) and the total intrinsic value of options exercised was $2.6 million (December 31, 2015 - $12.0 million).

The following table summarizes the employee share option plan as at December 31, 2016:

	Options outstanding				Options exercisable			
	Number outstanding		Weighted average exercise price	Weighted average remaining contractual life	Number exercisable		Weighted average exercise price	Weighted average remaining contractual life
$14.24 to $18.00	177,750	$	15.11	2.25	177,750	$	15.11	2.25
$18.01 to $25.08	587,475		21.30	3.41	587,475		21.30	3.41
$25.09 to $50.89	3,354,161		35.25	4.66	2,513,908		33.81	4.78
	4,119,386	**$**	**32.39**	**4.37**	**3,279,133**	**$**	**30.56**	**4.39**

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

Year ended December 31	**2016**	2015
Fair value per option ($)	**2.09**	2.98
Risk-free interest rate (%)	**1.12**	1.16
Expected life (years)	**6**	6
Expected volatility (%)	**20.65**	18.84
Annual dividend per share ($)	**1.98**	1.77
Forfeiture rate (%)	**16.00**	16.00

MTIP and DSUP

AltaGas has a MTIP for employees and executive officers, which includes RUs and PUs with vesting periods between 36 to 44 months from the grant date. In addition, AltaGas has a DSUP, which allows granting of DSUs to directors. DSUs granted under the DSUP vests immediately but settlement of the DSUs occur when the individual ceases to be a director.

PUs, RUs, and DSUs	**December 31, 2016**	December 31, 2015
(number of units)		
Balance, beginning of year	**409,037**	282,817
Granted	**91,288**	196,770
Vested and paid out	**(136,359)**	(71,883)
Forfeited	**(28,250)**	(7,133)
Units in lieu of dividends	**14,438**	8,466
Outstanding, end of year	**350,154**	409,037

For the year ended December 31, 2016, the compensation expense recorded for the MTIP and DSUP was $7.0 million (2015 - $3.3 million). As at December 31, 2016, the unrecognized compensation expense relating to the remaining vesting period for the MTIP was $11.9 million (December 31, 2015 - $12.6 million) and is expected to be recognized over the vesting period.

21. NET INCOME PER COMMON SHARE

The following table summarizes the computation of net income per common share:

For the year ended December 31		**2016**		2015
Numerator:				
Net income applicable to controlling interests	**$**	**203.5**	$	51.1
Less: Preferred share dividends		**(48.1)**		(41.2)
Net income applicable to common shares	**$**	**155.4**	$	9.9
Denominator:				
(millions)				
Weighted average number of common shares outstanding		**157.2**		137.7
Dilutive equity instruments[(a)]		**0.4**		1.0
Weighted average number of common shares outstanding - diluted		**157.6**		138.7
Basic net income per common share	**$**	**0.99**	$	0.07
Diluted net income per common share	**$**	**0.99**	$	0.07

(a) Includes all options that have a strike price lower than the share price of AltaGas' common shares as at December 31, 2016 and 2015.

For the year ended December 31, 2016, 2.2 million of share options (2015 – 1.6 million) were excluded from the diluted net income per share calculation as their effects were anti-dilutive.

22. OTHER INCOME (LOSS)

Year ended December 31		**2016**		2015
Gains from sale of assets	**$**	**4.2**	$	0.3
Interest income and other revenue		**3.9**		5.2
Other than temporary impairment of available-for-sale investments		**—**		(35.4)
Unrealized gains from held-for-trading assets		**0.5**		1.2
	$	**8.6**	$	(28.7)

23. OPERATING LEASES

Certain of AltaGas’ revenues are obtained through power purchase agreements or take-or-pay contracts whereby AltaGas is the lessor in these operating lease arrangements. Minimum lease payments received are amortized over the term of the lease. Contingent rentals are recorded when the condition that created the present obligation to make such payments occurs such as when actual electricity is generated and delivered. The carrying value of property, plant, and equipment associated with these leases was $3.1 billion as at December 31, 2016 (December 31, 2015 - $2.8 billion). For the year ended December 31, 2016, the total revenue earned from minimum lease payments was $238.2 million (2015 - $111.1 million) and from contingent rentals was $116.3 million (2015 - $102.8 million).

The following table sets forth the future fixed minimum revenue related to the operating leases for the years ended December 31:

2017	266.0
2018	266.0
2019	266.0
2020	234.7
2021	191.0

24. PENSION PLANS AND RETIREE BENEFITS

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

Defined Contribution Plan

AltaGas has a defined contribution (DC) pension plan for substantially all employees who are not members of defined benefit plans. The pension cost recorded for the DC plan was $8.1 million for the year ended December 31, 2016 (2015 - $7.4 million).

Defined Benefit Plans

AltaGas has several defined benefit pension plans in Canada and the United States for unionized and non-unionized employees. These benefit plans are funded.

Supplemental Executive Retirement Plan (SERP)

AltaGas has non-registered, defined benefit plans that provide defined benefit pension benefits to eligible executives based on average earnings, years of service and age at retirement. The SERP benefits will be paid from the general revenue of the Corporation as payments come due. Security will be provided for the SERP benefits through a letter of credit within a retirement compensation arrangement trust account.

Post-Retirement Benefits

AltaGas has several post-retirement benefit plans for unionized and non-unionized employees in Canada and the United States. Benefits provided to retired employees are limited to the payment of life insurance and health insurance premiums. These benefit plans are not funded, except for one plan. Post-retirement benefit plans in the United States provide certain medical and prescription drug benefits to eligible retired employees, their spouses and covered dependents. Benefits are based on a combination of the retiree's age and years of service at retirement. These benefit plans are funded.

AltaGas' most recent actuarial valuation of the Canadian defined benefit plans for funding purposes was completed in 2013. AltaGas is required to file an actuarial valuation of its Canadian defined benefit plans with the pension regulators at least every three years. The next actuarial valuation for funding purposes is required to be completed as of a date no later than December 31, 2016 and is expected to be filed with the pension regulators in 2017. Actuarial valuations are required annually for AltaGas' U.S. defined benefit plans.

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

	Canada		United States		Total	
Year ended December 31, 2016	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Accrued benefit obligation						
Balance, beginning of year	$ **135.1**	$ **14.7**	$ **280.0**	$ **88.0**	$ **415.1**	$ **102.7**
Actuarial loss (gain)	**7.9**	**0.8**	**8.8**	**(13.4)**	**16.7**	**(12.6)**
Current service cost	**7.0**	**0.6**	**7.1**	**1.9**	**14.1**	**2.5**
Member contributions	**0.2**	**—**	**—**	**—**	**0.2**	**—**
Interest cost	**5.6**	**0.6**	**11.8**	**3.9**	**17.4**	**4.5**
Benefits paid	**(5.7)**	**(0.3)**	**(8.2)**	**(2.9)**	**(13.9)**	**(3.2)**
Expenses paid	**(0.3)**	**—**	**—**	**—**	**(0.3)**	**—**
Net transfer in (out) (including the effect of acquisitions/divestitures)	**0.2**	**—**	**—**	**—**	**0.2**	**—**
Plan amendments	**—**	**—**	**—**	**(2.0)**	**—**	**(2.0)**
Plan settlements	**—**	**—**	**(0.9)**	**—**	**(0.9)**	**—**
Foreign exchange translation	**—**	**—**	**(8.1)**	**(2.8)**	**(8.1)**	**(2.8)**
Balance, end of year	$ **150.0**	$ **16.4**	$ **290.5**	$ **72.7**	$ **440.5**	$ **89.1**
Plan assets						
Fair value, beginning of year	$ **93.5**	$ **5.7**	$ **214.8**	$ **66.2**	$ **308.3**	$ **71.9**
Actual return on plan assets	**6.1**	**0.2**	**15.9**	**4.9**	**22.0**	**5.1**
Employer contributions	**7.5**	**1.2**	**11.5**	**0.9**	**19.0**	**2.1**
Member contributions	**0.2**	**—**	**—**	**—**	**0.2**	**—**
Benefits paid	**(5.7)**	**(0.3)**	**(8.2)**	**(2.9)**	**(13.9)**	**(3.2)**
Expenses paid	**(0.3)**	**—**	**—**	**—**	**(0.3)**	**—**
Acquisitions/ divestitures	**0.2**	**—**	**—**	**—**	**0.2**	**—**
Plan settlements	**—**	**—**	**(0.9)**	**—**	**(0.9)**	**—**
Foreign exchange translation	**—**	**—**	**(6.2)**	**(1.9)**	**(6.2)**	**(1.9)**
Fair value, end of year	$ **101.5**	$ **6.8**	$ **226.9**	$ **67.2**	$ **328.4**	$ **74.0**
Accrued benefit liability	$ **(48.5)**	$ **(9.6)**	$ **(63.6)**	$ **(5.5)**	$ **(112.1)**	$ **(15.1)**

Year ended December 31, 2015	Canada		United States		Total	
	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits	Defined Benefit	Post-Retirement Benefits
Accrued benefit obligation						
Balance, beginning of year	$ 130.8	$ 14.4	$ 238.7	$ 77.3	$ 369.5	$ 91.7
Actuarial loss	(4.3)	(0.6)	(15.7)	(7.9)	(20.0)	(8.5)
Current service cost	7.0	0.6	7.9	2.0	14.9	2.6
Member contributions	0.2	—	—	—	0.2	—
Interest cost	5.2	0.6	10.7	3.5	15.9	4.1
Benefits paid	(4.0)	(0.3)	(7.3)	(1.9)	(11.3)	(2.2)
Expenses paid	(0.4)	—	—	—	(0.4)	—
Plan amendments	0.6	—	—	0.4	0.6	0.4
Foreign exchange translation	—	—	45.7	14.6	45.7	14.6
Balance, end of year	$ 135.1	$ 14.7	$ 280.0	$ 88.0	$ 415.1	$ 102.7
Plan assets						
Fair value, beginning of year	$ 90.3	$ 4.7	$ 177.6	$ 56.8	$ 267.9	$ 61.5
Actual return on plan assets	1.2	0.1	(0.7)	0.1	0.5	0.2
Employer contributions	6.2	1.2	10.7	0.4	16.9	1.6
Member contributions	0.2	—	—	—	0.2	—
Benefits paid	(4.0)	(0.3)	(7.3)	(1.9)	(11.3)	(2.2)
Expenses paid	(0.4)	—	—	—	(0.4)	—
Foreign exchange translation	—	—	34.5	10.8	34.5	10.8
Fair value, end of year	$ 93.5	$ 5.7	$ 214.8	$ 66.2	$ 308.3	$ 71.9
Accrued benefit liability	$ (41.6)	$ (9.0)	$ (65.2)	$ (21.8)	$ (106.8)	$ (30.8)

The following amounts were included in the Consolidated Balance Sheets:

	December 31, 2016		December 31, 2015	
	Defined Benefit	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
Other assets *(note 10)*	**$ —**	**$ 2.8**	$ —	$ —
Accounts payable and accrued liabilities	**(0.5)**	**—**	(0.7)	—
Future employee obligations	**(111.6)**	**(17.9)**	(106.1)	(30.8)
	$ (112.1)	**$ (15.1)**	$ (106.8)	$ (30.8)

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

Year ended December 31, 2016	**Canada**		**United States**		**Total**	
	Defined Benefit	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**	**Defined Benefit**	**Post-Retirement Benefits**
Past service cost	**$ (0.5)**	**$ —**	**$ —**	**$ (0.3)**	**$ (0.5)**	**$ (0.3)**
Net actuarial loss	**(13.7)**	**(1.0)**	**—**	**—**	**(13.7)**	**(1.0)**
Recognized in AOCI pre-tax	**$ (14.2)**	**$ (1.0)**	**$ —**	**$ (0.3)**	**$ (14.2)**	**$ (1.3)**
Increase (decrease) by the amount included in deferred tax liabilities	**3.8**	**0.3**	**—**	**0.1**	**3.8**	**0.4**
Net amount in AOCI after-tax	**$ (10.4)**	**$ (0.7)**	**$ —**	**$ (0.2)**	**$ (10.4)**	**$ (0.9)**

Year ended December 31, 2015		Canada Defined Benefit		Canada Post-Retirement Benefits		United States Defined Benefit		United States Post-Retirement Benefits		Total Defined Benefit		Total Post-Retirement Benefits
Past service cost	$	(0.7)	$	—	$	—	$	(0.8)	$	(0.7)	$	(0.8)
Net actuarial loss		(11.3)		(0.7)		—		—		(11.3)		(0.7)
Recognized in AOCI pre-tax	$	(12.0)	$	(0.7)	$	—	$	(0.8)	$	(12.0)	$	(1.5)
Increase (decrease) by the amount included in deferred tax liabilities		3.1		0.2		—		0.6		3.1		0.8
Net amount in AOCI after-tax	$	(8.9)	$	(0.5)	$	—	$	(0.2)	$	(8.9)	$	(0.7)

The costs of the defined benefit and post-retirement benefit plans are based on management's estimate of the future rate of return on the fair value of pension plan assets, salary escalations, mortality rates and other factors affecting the payment of future benefits.

Amounts to be amortized in the next fiscal year from AOCI		Defined Benefit		Post-Retirement Benefits
Past service costs	$	0.2	$	—
Actuarial losses		0.9		—
Total	**$**	**1.1**	**$**	**—**

The net pension expense by plan for the period was as follows:

Year ended December 31, 2016		**Canada Defined Benefit**		**Canada Post-retirement Benefits**		**United States Defined Benefit**		**United States Post-retirement Benefits**		**Total Defined Benefit**		**Total Post-retirement Benefits**
Current service cost	**$**	**7.0**	**$**	**0.6**	**$**	**7.1**	**$**	**1.9**	**$**	**14.1**	**$**	**2.5**
Interest cost		**5.6**		**0.6**		**11.8**		**3.9**		**17.4**		**4.5**
Expected return on plan assets		**(5.3)**		**(0.2)**		**(15.1)**		**(4.5)**		**(20.4)**		**(4.7)**
Settlement (gain) loss		**—**		**—**		**0.1**		**—**		**0.1**		**—**
Amortization of past service cost		**0.2**		**—**		**—**		**—**		**0.2**		**—**
Amortization of net actuarial loss		**0.8**		**0.1**		**—**		**—**		**0.8**		**0.1**
Amortization of regulatory asset		**1.2**		**—**		**6.3**		**0.8**		**7.5**		**0.8**
Net benefit cost recognized	**$**	**9.5**	**$**	**1.1**	**$**	**10.2**	**$**	**2.1**	**$**	**19.7**	**$**	**3.2**

Year ended December 31, 2015		Canada Defined Benefit		Canada Post-retirement Benefits		United States Defined Benefit		United States Post-retirement Benefits		Total Defined Benefit		Total Post-retirement Benefits
Current service cost	$	7.0	$	0.6	$	7.9	$	2.0	$	14.9	$	2.6
Interest cost		5.2		0.6		10.7		3.5		15.9		4.1
Expected return on plan assets		(5.1)		(0.2)		(14.8)		(4.6)		(19.9)		(4.8)
Amortization of past service cost		0.1		—		—		—		0.1		—
Amortization of net actuarial loss		0.8		—		—		—		0.8		—
Amortization of regulatory asset		1.4		0.1		6.7		1.2		8.1		1.3
Net benefit cost recognized	$	9.4	$	1.1	$	10.5	$	2.1	$	19.9		3.2

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

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

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

The Corporation has a target asset mix for the Canadian plans of 45 percent to 55 percent fixed income assets. The target asset mix for the U.S. plans is 33 percent fixed income assets. These objectives have taken into account the nature of the liabilities and the risk-reward tolerance of the Corporation.

The collective investment mixes for the plans are as follows as at December 31, 2016:

Canada	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	$ **5.2**	$ 5.2	$ —	4.8
Canadian equities	**35.5**	35.5	—	32.8
Foreign equities	**17.7**	17.7	—	16.3
Fixed income	**43.9**	43.8	0.1	40.5
Real estate	**6.0**	—	6.0	5.6
	$ **108.3**	$ 102.2	$ 6.1	100.0

United States	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	$ **0.8**	$ 0.8	$ —	0.3
Foreign equities	**192.5**	192.5	—	65.4
Fixed income	**100.8**	100.8	—	34.3
	$ **294.1**	$ 294.1	$ —	100.0

Total	**Fair value**	Level 1	Level 2	Percentage of Plan Assets (%)
Cash and short-term equivalents	$ **6.0**	$ 6.0	$ —	1.5
Canadian equities	**35.5**	35.5	—	8.8
Foreign equities	**210.2**	210.2	—	52.2
Fixed Income	**144.7**	144.6	0.1	36.0
Real Estate	**6.0**	—	6.0	1.5
	$ **402.4**	$ 396.3	$ 6.1	100.0

Significant actuarial assumptions used in measuring net benefit plan costs	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
For the year ended December 31	**2016**		2015	
Discount rate (%)	**2.70 - 4.50**	**4.20 - 4.60**	3.40 - 4.10	4.10
Expected long-term rate of return on plan assets (%) [(a)]	**6.00 - 7.30**	**3.10 - 7.30**	6.00 - 7.50	3.10 - 7.50
Rate of compensation increase (%)	**2.75 - 4.00**	**3.25**	3.00 - 4.00	3.50
Average remaining service life of active employees (years)	**12.5**	**13.6**	12.6	13.5

(a) Only applicable for funded plans

Significant actuarial assumptions used in measuring benefit obligations	**Defined Benefit**	**Post-Retirement Benefits**	Defined Benefit	Post-Retirement Benefits
As at December 31	**2016**		2015	
Discount rate (%)	**2.65 - 4.20**	**4.00 - 4.20**	2.70 - 4.50	4.20 - 4.60
Rate of compensation increase (%)	**2.75 - 4.00**	**3.25**	2.75 - 4.00	3.25

The expected rate of return on assets is based on the current level of expected returns on risk free investments, the historical level of risk premium associated with other asset classes in which the portfolio is invested, and the expectations for future returns of each asset class. The expected return for each asset class was then weighted based on the target asset allocation to develop the expected rate of return on assets assumption for the portfolio.

The discount rate is based on high-quality long-term corporate bonds, with maturities matching the estimated timing and amount of expected benefit payments.

The estimates for health care benefits take into consideration increased health care benefits due to aging and cost increases in the future. The assumed initial health care cost trend rates used to measure the expected cost of benefits range between 6.8 and 7.2 percent and the ultimate trend rate between 4.5 and 5 percent, which is expected to be achieved by 2029.

The assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one percentage point change in the assumed health care trend rates would have the following effects for 2016:

		Increase		Decrease
Service and interest costs	$	2.3	$	(1.5)
Accrued benefit obligation	$	16.6	$	(13.5)

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

		Defined Benefit		Post-Retirement Benefits
Expected employer contributions:				
2017	$	17.6	$	3.5
Expected benefit payments:				
2017	$	15.7	$	2.9
2018		16.8		3.1
2019		18.1		3.2
2020		19.5		3.5
2021		20.6		3.7
2022 - 2026	$	121.2	$	21.2

25. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

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

Future payments of these commitments at December 31, 2016 are estimated as follows:

	2017	2018	2019	2020	2021	2022 and beyond	Total
Gas purchase[(a)]	$ 377.0	$ 319.4	$ 323.5	$ 318.8	$ 265.4	$ 411.8	**$ 2,015.9**
Service agreement[(b)(c)]	9.6	22.0	17.0	13.1	11.1	152.7	**225.5**
Storage services[(d)]	3.5	3.5	3.5	3.5	3.6	29.4	**47.0**
Capital projects[(e)]	33.8	—	—	—	—	—	**33.8**
Operating leases[(f)]	32.7	7.1	16.5	4.8	4.5	21.9	**87.5**
	$ 456.6	$ 352.0	$ 360.5	$ 340.2	$ 284.6	$ 615.8	**$ 2,409.7**

(a) AltaGas enters into contracts to purchase natural gas and natural gas transportation and storage services from various suppliers for its utilities. These contracts, which have expiration dates that range from 2017 to 2033, are used to ensure that there is an adequate supply of natural gas to meet the needs of customers and to minimize exposure to market price fluctuations.

(b) In 2014, AltaGas' Blythe facility entered into a Long-Term Service Agreement with Siemens to complete various upgrade and maintenance services on the Combustion Turbines at the Blythe facility over 116,000 EOH/CT, or 20 years, whichever comes first. The LTSA has fixed fees that will be incurred in the five years following December 31, 2014 and variable fees on a per equivalent operating hour (EOH) basis. As at December 31, 2016, the total commitment was $216.5 million payable over the next 17 years, of which $63.9 million is expected to be paid over the next five years.

(c) In 2007, AltaGas entered into a service and maintenance agreement with Enercon GmbH for the wind turbines for Bear Mountain. AltaGas has an obligation to pay a minimum of $8.9 million over the next five years.

(d) In 2009, AltaGas entered into a 20-year storage contract at the Dawn Hub in southwest Ontario. AltaGas is obligated to pay approximately $3.5 million per annum over the term of the contract for storage services.

(e) Commitments for capital projects. Estimated amounts are subject to variability depending on the actual construction costs.

(f) Operating leases include lease arrangements for office spaces, vehicles, office and other equipment.

Guarantees

On October 2014, Heritage Gas Limited, a wholly-owned subsidiary of AltaGas, entered into a throughput contract entered into a throughput contract with Spectra Energy for the use of the expansion of its Algonquin Gas Transmission and Maritimes & Northeast Pipeline systems. The contract will commence upon completion of the construction of the pipelines and it will expire 15 years thereafter. AltaGas has two guarantees outstanding that total US$91.7 million to stand by all payment obligations under the transportation agreement.

Contingencies

AltaGas and its subsidiaries are subject to various legal claims and actions arising in the normal course of business. While the final outcome of such legal claims and actions cannot be predicted with certainty, the Corporation does not believe that the resolution of such claims and actions will not have a material impact on the Corporation's consolidated financial position or results of operations.

26. RELATED PARTY TRANSACTIONS

In the normal course of business, AltaGas transacts with its subsidiaries, affiliates and joint ventures. Amounts due to or from related parties on the Consolidated Balance Sheets were measured at the exchange amount and were as follows:

As at		**December 31, 2016**		December 31, 2015
Due from related parties				
Accounts receivable [(a)]	**$**	**0.7**	$	0.6
Long-term investments and other assets [(b)(c)]		**63.3**		0.8
	$	**64.0**	$	1.4
Due to related parties				
Accounts payable [(d)]		**3.2**		6.2
	$	**3.2**	$	6.2

(a) Receivable from joint ventures and an affiliate.

(b) AltaGas and one of its executives agreed to a loan in the principal amount of $0.8 million to be paid in full with accrued interest at the rate prescribed by the Income Tax Act (Canada) on the earlier of the date of employment termination and February 8, 2021. The provisions of the loan were amended in 2015 to include provision for forgiveness of the loan at a rate of 20 percent per annum commencing in 2017. Such forgiveness is conditional on the executive's continued employment with AltaGas.

(c) AltaGas has provided a $100.0 million interest bearing secured loan facility to Petrogas of which $50.0 million is committed. The facility is available for Petrogas to draw upon from time to time for general corporate purposes. The facility is subject to annual renewal and has a maturity date of June 27, 2021. As at December 31, 2016, Petrogas had drawn $62.5 million under the facility.

(d) Payables to joint ventures.

The following transactions with related parties have been recorded on the Consolidated Statements of Income for the year ended December 31, 2016 and 2015:

Year ended December 31		**2016**		2015
Revenue [(a)(b)]	**$**	**16.1**	$	33.0
Cost of sales [(c)]	**$**	**(6.5)**	$	(10.1)
Operating and administrative expenses [(d)]	**$**	**0.7**	$	1.3
Other income [(e)]	**$**	**1.3**	$	0.5

(a) In the ordinary course of business, AltaGas sold natural gas and natural gas liquids to a joint venture and an affiliate, as well as provided processing services to a joint venture.

(b) In 2016, PNG recognized revenue of $6.8 million related to the recovery of development costs from Triton LNG Limited Partnership for the PNG Pipeline Looping Project.

(c) In the ordinary course of business, AltaGas obtained natural gas storage services from a joint venture as well as incurred costs related to the sale of natural gas liquids to an affiliate.

(d) Administrative costs recovered from joint ventures.

(e) Interest income from an affiliate.

27. SUPPLEMENTAL CASH FLOW INFORMATION

The following table details the changes in operating assets and liabilities from operating activities:

For the year ended December 31		2016		2015
Source (use) of cash:				
Accounts receivable	**$**	**(6.1)**	$	68.7
Inventory		**(14.4)**		(7.7)
Other current assets		**(20.8)**		(2.0)
Regulatory assets (current)		**3.3**		11.4
Accounts payable and accrued liabilities		**(4.6)**		(15.1)
Customer deposits		**(4.6)**		1.4
Regulatory liabilities (current)		**(4.1)**		9.2
Other current liabilities		**4.3**		(5.3)
Other operating assets and liabilities		**(30.5)**		(21.4)
Changes in operating assets and liabilities	**$**	**(77.5)**	$	39.2

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

For the year ended December 31		2016		2015
Interest paid (net of capitalized interest)	**$**	**141.5**	$	126.5
Income taxes paid	**$**	**35.9**	$	20.1

28. SEGMENTED INFORMATION

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

Gas	– NGL processing and extraction plants; – transmission pipelines to transport natural gas and NGL; – natural gas gathering lines and field processing facilities; – purchase and sale of natural gas, including to commercial and industrial users; – natural gas storage facilities; – liquefied petroleum gas (LPG) terminal currently under construction; and – equity investment in Petrogas, a North American entity engaged in the marketing, storage and distribution of NGL, drilling fluids, crude oil and condensate diluents.
Power	– natural gas-fired, wind, biomass and hydro power generation assets, whereby outputs are generally sold under long term power purchase agreements, both operational and under development; – energy storage; and – sale of power to commercial and industrial users in Alberta.
Utilities	– rate-regulated natural gas distribution assets in Michigan, Alaska, Alberta, British Columbia and Nova Scotia; and – rate-regulated natural gas storage in Michigan and Alaska.
Corporate	– the cost of providing corporate services, financing and general corporate overhead, investments in certain public and private entities, corporate assets, financing other segments and the effects of changes in the fair value of risk management contracts.

Geographic Information

Year ended December 31	2016	2015
Revenue[(a)]		
Canada	$ 1,192.3	$ 1,279.0
United States	1,008.8	904.4
Total	$ 2,201.1	$ 2,183.4

(a) Operating revenue from external customers, excluding unrealized gains (losses) on risk management contracts.

As at December 31	2016	2015
Property, plant and equipment		
Canada	$ 4,080.3	$ 3,914.0
United States	2,654.6	2,683.9
Total	$ 6,734.9	$ 6,597.9

The following tables show the composition by segment:

	Year ended December 31, 2016					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[(a)]	Total
Revenue	$ 804.1	$ 574.7	$ 1,065.8	$ 11.7	$ (255.2)	$ 2,201.1
Unrealized gains (losses) on risk management	—	—	0.5	(11.9)	—	(11.4)
Cost of sales	(496.1)	(200.5)	(557.1)	—	236.8	(1,016.9)
Operating and administrative	(154.3)	(100.1)	(229.7)	(44.1)	18.9	(509.3)
Accretion expenses	(3.9)	(7.0)	(0.1)	—	—	(11.0)
Depreciation and amortization	(65.8)	(108.7)	(82.3)	(14.7)	—	(271.5)
Income (loss) from equity investments	7.6	(6.8)	2.6	—	—	3.4
Other income (loss)	4.8	—	1.7	2.6	(0.5)	8.6
Foreign exchange gains	—	—	—	4.0	—	4.0
Interest expense	—	—	—	(150.8)	—	(150.8)
Income (loss) before income taxes	$ 96.4	$ 151.6	$ 201.4	$ (203.2)	$ —	$ 246.2
Net additions (reductions) to:						
Property, plant and equipment[(b)]	$ 193.0	$ 95.0	$ 112.7	$ 4.3	$ —	$ 405.0
Intangible assets	$ 2.6	$ 15.1	$ 2.4	$ 5.9	$ —	$ 26.0

(a) Intersegment transactions are recorded at market value.

(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash flow due to classification of business acquisition and foreign exchange changes on U.S. assets.

	Year ended December 31, 2015					
	Gas	Power	Utilities	Corporate	Intersegment Elimination[a]	Total
Revenue	$ 845.5	$ 476.2	$ 1,076.5	$ 1.1	$ (215.9)	$ 2,183.4
Unrealized gains on risk management	—	—	—	9.4	—	9.4
Cost of sales	(503.2)	(214.4)	(595.8)	—	208.5	(1,104.9)
Operating and administrative	(175.4)	(68.7)	(228.3)	(26.5)	7.0	(491.9)
Accretion expenses	(3.7)	(7.2)	(0.1)	—	—	(11.0)
Depreciation and amortization	(62.7)	(63.8)	(76.1)	(10.2)	0.9	(211.9)
Provisions on assets	(22.3)	(28.4)	(2.8)	—	—	(53.5)
Loss from equity investments	(17.0)	(44.0)	(2.4)	—	—	(63.4)
Other income (loss)	—	0.5	2.7	(31.4)	(0.5)	(28.7)
Foreign exchange gains	—	—	—	6.0	—	6.0
Interest expense	—	—	—	(125.5)	—	(125.5)
Income (loss) before income taxes	$ 61.2	$ 50.2	$ 173.7	$ (177.1)	$ —	$ 108.0
Net additions (reductions) to:						
Property, plant and equipment[b]	$ 262.6	$ 693.0	$ 185.6	$ 8.7	$ —	$ 1,149.9
Intangible assets	$ 2.8	$ 375.6	$ 3.9	$ 13.4	$ —	$ 395.7

(a) Intersegment transactions are recorded at market value.

(b) Net additions to property, plant, and equipment, and intangible assets may not agree to changes reflected in the Consolidated Statement of Cash flow due to classification of business acquisition and foreign exchange changes on U.S. assets.

The following table shows goodwill and total assets by segment:

	Gas	Power	Utilities	Corporate	Total
As at December 31, 2016					
Goodwill	**$ 152.9**	**$ —**	**$ 703.1**	**$ —**	**$ 856.0**
Segmented assets	**$ 2,826.3**	**$ 3,501.3**	**$ 3,586.4**	**$ 286.6**	**$ 10,200.6**
As at December 31, 2015					
Goodwill	$ 156.3	$ —	$ 721.0	$ —	$ 877.3
Segmented assets	$ 2,449.0	$ 3,579.9	$ 3,576.7	$ 493.9	$ 10,099.5

29. SUBSEQUENT EVENTS

Subsequent events have been reviewed through February 22, 2017, the date these Consolidated Financial Statements were issued.

Pending Acquisition of WGL Holdings, Inc. (WGL)

On January 25, 2017, the Corporation entered into a definitive agreement (the Merger Agreement) to indirectly acquire WGL Holdings, Inc. (NYSE:WGL) (the WGL Acquisition). Pursuant to the Merger Agreement, following the consummation of the WGL Acquisition, WGL common shareholders will receive US$88.25 per common share in cash, which represents a total enterprise value of $8.4 billion, including the assumption of approximately $2.4 billion of debt as at September 30, 2016.

WGL is a diversified energy infrastructure company and the sole common shareholder of Washington Gas, a regulated natural gas utility headquartered in Washington, D.C., serving more than 1.1 million customers in Maryland, Virginia, and the District of Columbia. WGL has a growing midstream business with investments in natural 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 terminal in Maryland being developed by a third party, currently expected to be operational in late 2017. WGL also owns contracted clean power assets, with a focus on distributed generation and energy efficiency assets throughout the United States. In addition, WGL has a retail gas and power marketing business with approximately 260,000 customers in Maryland, Virginia, Delaware, Pennsylvania and the District of Columbia. Upon completion of the WGL Acquisition, AltaGas will have over $22 billion of assets and more than 1.7 million rate regulated gas customers.

The WGL Acquisition is not subject to any financing contingency. AltaGas expects that cash to close the WGL Acquisition will be provided from a combination of the net proceeds from a $400 million private placement of subscription receipts to OMERS, the pension plan for Ontario's municipal employees, and a bought deal subscription receipt offering for gross proceeds of approximately $2.1 billion (see *Subscription Receipts* section below), subsequent offerings of senior debt, hybrid securities, equity or equity-linked securities (including Preferred Shares or convertible debentures), select AltaGas asset sales and through a fully committed US$3.1 billion bridge facility, which would be available for 12 to 18 months following closing of the WGL Acquisition. AltaGas believes there are a number of attractive, actionable opportunities to monetize certain of its assets in a manner which supports the Corporation’s long term strategy of growing in attractive areas and maintaining a long term, balanced mix of energy infrastructure assets across its Gas, Power and Utility business segments. The timing of these subsequent offerings and asset sales is subject to prevailing market conditions, but are expected to be completed prior to the closing of the WGL Acquisition.

The WGL Acquisition is subject to certain closing conditions, including approval of WGL common shareholders and certain regulatory and government approvals, including approval by the Public Service Commission of the District of Columbia, The Maryland Public Service Commission, The Commonwealth of Virginia State Corporation Commission, the United States Federal Energy Regulatory Commission, and the Committee on Foreign Investment in the United States, and expiration or termination of any applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended.

Subscription Receipts

On February 3, 2017, the Corporation issued approximately 80.7 million subscription receipts to partially fund the WGL Acquisition at a price of $31 each for total gross proceeds of approximately $2.5 billion. Each subscription receipt entitles the holder to automatically receive one common share upon closing of the WGL Acquisition. While the subscription receipts remain outstanding, holders will be entitled to receive cash payments (Dividend Equivalent Payments) per subscription receipt that are equal to dividends declared on each common share. Such Dividend Equivalent Payments will have the same record date as the related common share dividend and will be paid to holders of the subscription receipts concurrently with the payment date of each such common share dividend. The Dividend Equivalent Payments will be paid first out of any interest on the escrowed funds and then out of the escrowed funds. If the Merger Agreement is terminated after the common share dividend declaration date, but before the common share dividend record date, subscription receipt holders of record on the termination date shall receive a pro-rata payment of the dividend as the Dividend Equivalent Payment. If the Merger Agreement is terminated on a record date or following a record date but on or prior to the dividend payment date, holders will be entitled to receive the full Dividend Equivalent Payment.

The net proceeds from the sale of the subscription receipts are held by an escrow agent pending, among other things, receipt of all regulatory and government approvals required to finalize the acquisition of WGL and confirmation that 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, but for the payment of the purchase price, and AltaGas has available to it all other funds required to complete the WGL Acquisition. If the escrow release notice and direction is not delivered on or prior to 5:00 pm (Calgary time) on September 4, 2018, the Corporation will be required to make a termination payment equal to the aggregate issue price of such holder’s subscription receipts plus any unpaid Dividend Equivalent Payments owing to such holder of subscription receipts.

Preferred Shares

On February 22, 2017, AltaGas issued 12,000,000 cumulative 5-Year minimum rate reset redeemable preferred shares, Series K, at a price of $25 per Series K preferred share for aggregate gross proceeds of $300 million on a bought deal basis. Holders of the Series K preferred shares will be entitled to receive a cumulative quarterly fixed dividend for the initial period ending on but excluding March 31, 2022 at an annual rate of 5.0 percent, payable on the last day of March, June, September and December, as and when declared by the Board of Directors of AltaGas. The first quarterly dividend payment is payable on June 30, 2017 in the amount of $0.4384 per Series K Preferred Share. The dividend rate will reset on March 31, 2022 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 3.8 percent, provided that, in any event, such rate shall not be less than 5.0 percent per annum. The Series K preferred shares are redeemable by AltaGas, at its option, on March 31, 2022 and on March 31 of every fifth year thereafter.

Holders of Series K preferred shares will have the right to convert all or any part of their shares into cumulative redeemable floating rate preferred shares, Series L, subject to certain conditions, on March 31, 2022 and on March 31 every fifth year thereafter. Holders of Series L preferred shares will be entitled to receive a cumulative quarterly floating dividend at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill yield plus 3.8 percent, as and when declared by the Board of Directors of AltaGas.

Supplementary Quarterly Operating Information

	Q4-16	**Q3-16**	Q2-16	Q1-16	Q4-15
OPERATING HIGHLIGHTS					
GAS					
Total inlet gas processed (Mmcf/d)(1)	**1,337**	1,275	1,083	1,222	1,298
Extraction volumes (Bbls/d)(1)(2)	**69,687**	65,509	58,065	64,408	65,465
Frac spread - realized ($/Bbl)(1)(3)	**6.11**	6.29	10.00	8.22	15.55
Frac spread - average spot price ($/Bbl)(1)(4)	**8.40**	6.29	10.62	8.22	5.06
POWER					
Renewable power sold (GWh)	**196**	670	544	142	310
Conventional power sold (GWh)	**374**	587	293	698	1,264
Renewable capacity factor (%)	**18.8**	70.2	56.8	10.5	30.2
Contracted conventional availability factor (%)(5)	**99.8**	99.3	92.4	97.6	99.1
UTILITIES					
Canadian utilities					
Natural gas deliveries - end-use (PJ)(6)	**10.8**	3.2	4.8	12.3	10.2
Natural gas deliveries - transportation (PJ)(6)	**1.5**	1.1	1.5	1.8	1.9
U.S. utilities					
Natural gas deliveries end use (Bcf) (6)	**22.8**	5.4	10.3	28.2	20.2
Natural gas deliveries transportation (Bcf)(6)	**14.2**	11.0	11.8	14.2	13.5
Service sites(7)	**574,875**	568,628	568,606	570,681	568,751
Degree day variance from normal - AUI (%)(8)	**(0.6)**	(8.4)	(28.0)	(18.5)	(10.0)
Degree day variance from normal - Heritage Gas (%)(8)	**(1.0)**	(7.4)	3.6	(6.9)	(8.0)
Degree day variance from normal - SEMCO Gas (%)(9)	**(6.1)**	(57.6)	11.8	(8.5)	(20.4)
Degree day variance from normal - ENSTAR (%)(9)	**(1.4)**	(36.1)	(26.4)	(21.0)	(6.1)

(1) Average for the period.

(2) Includes Harmattan NGL processed on behalf of customers.

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

(4) Average spot frac spread or NGL margin, expressed in dollars per barrel of NGL, is indicative of the average sales price that AltaGas receives for propane, butane and condensate less extraction premiums, before accounting for hedges, divided by the respective frac exposed volumes for the period.

(5) 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.

(6) Petajoule (PJ) is one million gigajoules (GJ). Bcf is one billion cubic feet.

(7) Service sites reflect all of the service sites of AUI, PNG, Heritage Gas, and U.S. Utilities, including transportation and non-regulated business lines.

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

(9) A degree day for U.S. Utilities is a measure of coldness, determined daily as the number of degrees the average temperature during the day in question is below 65 degrees Fahrenheit. Degree days for a particular period are determined by adding the degree days incurred during each day of the period. Normal degree days for a particular period are the average of degree days during the prior 15 years for SEMCO Energy Gas Company and during the prior 10 years for ENSTAR.

Other Information

DEFINITIONS

Bbls/d	barrels per day
Bcf	billion cubic feet
GJ	gigajoule
GWh	gigawatt-hour
Mcf	thousand cubic feet
Mmcf/d	million cubic feet per day
MW	megawatt
MWh	megawatt-hour
MMBTU	million British thermal unit
PJ	petajoule
US$	United States dollar

ABOUT ALTAGAS

AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. The Corporation creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources. For more information visit: www.altagas.ca.

For further information contact:

Investment Community
1-877-691-7199
investor.relations@altagas.ca

Corporate Information

AltaGas is an energy infrastructure business with a focus on natural gas, power and regulated utilities. AltaGas creates value by acquiring, growing and optimizing its energy infrastructure, including a focus on clean energy sources.

MANAGEMENT TEAM

David Harris
President and Chief Executive Officer

Tim Watson
Executive Vice President and
Chief Financial Officer

John Lowe
Executive Vice President

Corine Bushfield
Executive Vice President
Chief Administrative Officer

John O'Brien
President AltaGas Services U.S.

Randy Toone
Executive Vice President
Commercial and Business
Development

Brad Grant
Vice President and General Counsel

Kent Stout
Senior Vice President
Organizational Development

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Investors are encouraged to contact Computershare for information concerning their security holdings.

STOCK EXCHANGE LISTING

Toronto Stock Exchange:
ALA, ALA.PR.A, ALA.PR.B, ALA.PR.U, ALA.PR.E, ALA.PR.G, ALA.PR.I, ALA.PR.K and ALA.R

DEFINITIONS

Bbls/d barrels per day
Bcf billion cubic feet
EBITDA earnings before interest, taxes, depreciation, and amortization
GJ gigajoule
GWh gigawatt-hour
Mcf thousand cubic feet
Mmcf/d million cubic feet per day
MW megawatt
MWh megawatt-hour
PJ petajoule
MMBTU million British thermal unit

Forward-looking Information

This message to shareholders may contain certain statements that are forward-looking and are subject to risks and uncertainties. The words "may", "would", "could", "should", "will", "intend", "plan", "anticipate", "expect", "believe", "aim", "focus", "seek", "propose", "estimate", "project", "grow", "target", "opportunity", "outlook", "forecast" or other similar words are used to identify such forward-looking statements. Forward looking statements in this message are intended to provide security holders and potential investors with information regarding AltaGas and its subsidiaries, including management's assessment of AltaGas' and its subsidiaries' future financial and operations plans and outlook. Forward-looking information in this message include, among other things, AltaGas' focus for 2017; AltaGas' transformational positioning for 2017; AltaGas' ability to enhance its reputation, to continue engagement with stakeholders and to maintain its commitment to clean energy; expectations regarding the acquisition of WGL Holdings, Inc. including the expected closing date, ability to obtain, and timeline for obtaining, regulatory and other approvals, the aggregate cash consideration, anticipated benefits of the 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, further diversity and the significance and quality of growth potential in the Montney and Marcellus/Utica formation; expectations with respect to the proposed Ridley Island Propane Export Terminal including expectations of being the first propane export terminal off the west coast of British Columbia, AltaGas' ability to offer a complete energy value chain to multiple markets, quality of Asian markets, sources of propane supply and timing of construction and commercial operations; 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, capacity, and expected timeline for commercial operations; and expectations relating to construction at the North Pine Facility and the ability of the facility to provide a new source of propane supply for Ridley Island Propane Export Terminal. All forward-looking statements reflect AltaGas' beliefs and assumptions based on information available at the time the statements were made. Actual results or events may differ from those predicted in these forward-looking statements. Factors that could cause actual results or events to differ materially from current expectations include, among others, the ability of AltaGas to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of AltaGas' assets, the construction and completion of projects, costs of labour, equipment and materials, access to capital markets, interest and currency exchange rates, the price, generation and availability of commodities and hedging, regulatory, First Nations and other stakeholder processes and decisions, changes in environmental and other laws and regulations, competitive factors in the natural gas and power energy sectors, performance and credit risk of counterparties, weather, and economic conditions. This list should not be considered to be exhaustive. By its nature, forward-looking statements are subject to various risks and uncertainties, which could cause AltaGas' actual results and experience to differ materially from the anticipated results or expectations expressed in such forward-looking statements. Additional information on these and other factors are available in the reports filed by AltaGas with Canadian securities regulators, including in the Annual Information Form available on SEDAR at www.sedar.com. Readers are cautioned to not place undue reliance on such forward-looking information that is given as of the date it is expressed in this message or other document in which it is contained and which is expressly qualified by cautionary statements contained in this message or other document in which such forward-looking information is contained. Readers are also cautioned not to use future-oriented information or financial outlooks for anything other than their intended purpose. AltaGas undertakes no obligation to update or revise any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

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