MANAGEMENT'S DISCUSSION AND ANALYSIS

The Management's Discussion and Analysis (MD&A) of operations and Consolidated Financial Statements presented herein are 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, 2015. This MD&A dated February 24, 2016, 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, 2015.

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", "would", "could", "should", "will", "intend", "plan", "anticipate", "believe", "aim", "seek", "propose", "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 others things, business objectives, the anticipated benefits of acquisitions and other major projects, the anticipated timing of commercial operations, investment decisions, expenditures, licensing and permitting, expected growth, capital expenditures, 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", "2015 Growth Highlights", "AltaGas Vision and Objective", "Strategy", "Owning and Operating Energy Infrastructure", "Strategy Execution", "2016 Outlook" and "Growth Capital" and under those headings specifically include AltaGas' expectations relating to natural gas supply, demand for clean energy and resulting opportunities for growth across all of AltaGas' business segments including prospects for growth of the gas segment in British Columbia and Alberta and potential opportunities to expand the power segment in California and across the U.S. and to develop new gas-fired and renewable generation in Alberta to replace coal; the potential for growth through increasing throughput at facilities and increasing interest in existing plants; 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; expectations relating to the Townsend Facility and related projects including progress of construction, expected costs, expected in service date, impact on earnings, capacity and connection capability of egress lines with Townsend Facility and truck terminal; AltaGas' belief that investing in low-risk, long-life energy assets will generate superior economic returns; AltaGas' expectations regarding diversification including impact on earnings and cash flow and 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 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 gas processing; AltaGas' belief that producers will seek to conserve capital and monetize non-core assets; 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 that AltaGas is in a 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 proposed Ridley Island Propane Export Terminal; AltaGas' plan to focus its resources on operating and optimizing AltaGas' larger plants and developing large scale opportunities as part of its northeast British Columbia strategy; 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; 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 that AltaGas' in-house construction expertise provides a competitive advantage; 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 producers; 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' ability to develop the proposed Ridley Island Propane Export Terminal, to operate LPG export terminals and 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, through AltaGas' relationship with Idemitsu; expectations for opportunities arising from increased demand 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 optionality provided by the location of the Blythe Energy Center, Blythe II and Blythe III and if CAISO becomes the Regional Transmission Organization incorporating Nevada and Arizona; expectations regarding the ability of the Blythe Energy Center, Blythe II and Blythe III to contract with multiple utilities and others, serve multiple markets, increase generating capacity and to deliver generation to customers in CAISO and other neighbouring states; expectations regarding Pomona including future bid plans and the ability to transition to merchant market; 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 relating to PNG's rates and timing of final decisions to be made by BCUC; expectations that advancing energy export opportunities will provide higher netbacks to producers; expectations with respect to the development of the proposed Ridley Island Propane Export Terminal including development costs, initial shipment capacity and timing of final investment decision and commercial operations; expectations relating to the development of the northeast British Columbia Liquids Separation Facility including connection capability to rail, existing AltaGas infrastructure and the proposed Ridley Island Propane Export Terminal, facility specifications and cost and timing of final investment decision; expectations that AltaGas is well-positioned to fund its growth capital and to take advantage of growth opportunities as they arise; expectations relating to the San Joaquin Facilities including strengthening AltaGas' overall California market position, expected contributions to growth and impact on earnings; expectations relating to the Northwest Hydro Facilities including expected contributions to earnings and seasonality impacts; expected impact on earnings of dispositions of non-core gas assets; expectations regarding Petrogas including plans for growth and earnings, expectations regarding commodity prices and commodity hedging; expectations regarding the US dollar; expected earnings from the utilities segment including from SEMCO Gas as a result of its Main Replacement Program; and expectations with respect to the Alton Natural Gas Storage Project including expected natural gas storage capacity, timing of completion of construction and in service date, expected reduction in natural gas price volatility and expectations that the project will provide security of gas supply, enhanced reliability and delivery of natural gas for customers of Heritage Gas.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Such statements reflect AltaGas' current views with respect to future events based on certain material factors and assumptions and are subject to certain risks and uncertainties including without limitation: changes in market competition, governmental or regulatory developments, changes in tax legislation, general economic conditions and other factors set out in AltaGas' public 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 or expected, and such forward-looking statements included in this MD&A herein 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 as cautionary statements.

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

Additional information relating to AltaGas can be found on its website at www.altagas.ca. The continuous disclosure materials of AltaGas, including its quarterly and annual MD&A and Consolidated Financial Statements, Annual Information Form, Management Information Circular, material change reports and press releases, are also available through AltaGas' website 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 Extraction and Transmission Limited Partnership, AltaGas Pipeline Partnership, AltaGas Processing Partnership, Harmattan Gas Processing Limited Partnership, AltaGas Utilities Inc. (AUI), Heritage Gas Limited (Heritage Gas), Pacific Northern Gas Ltd. (PNG), Coast Mountain Hydro Limited Partnership, AltaGas Services (U.S.) Inc., Blythe Energy Inc. (Blythe), AltaGas San Joaquin Energy Inc., 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. More than 1,700 employees across North America are focused on executing AltaGas' strategy through three business segments:

- Gas, which transacts more than 2 Bcf/d of natural gas and includes natural gas gathering and processing, natural gas liquids extraction and separation, transmission, storage, and natural gas marketing, as well as the Corporation's indirectly held one-third interest in Petrogas Energy Corp. (Petrogas). The Gas segment has significant prospects for growth in British Columbia and Alberta;
- Power, which includes generation assets located across North America with more than 2,000 MW of capacity from five fuel types, with significant opportunities to expand in California and across the United States, as well as the potential opportunity to develop new gas-fired and renewable generation in Alberta to replace coal; and
- Utilities, serving over 560,000 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, 2015, AltaGas' enterprise value exceeded $9 billion. With the physical and economic links along the energy value chain, primarily from wellhead to burner tip, together with its experienced and talented workforce and its efficient, reliable and profitable assets, market knowledge and financial discipline, AltaGas has provided strong, stable and predictable returns to its investors. AltaGas focuses on maximizing the profitability of its assets, adding services that are complementary to its existing business segments, and growing through the acquisition and development of energy infrastructure, including infrastructure required to provide access to new markets and higher netbacks to producers in the Western Canadian Sedimentary Basin (WCSB) by establishing a western energy hub in northeast British Columbia with access to export markets off the West Coast.

2015 GROWTH HIGHLIGHTS

- Completed the acquisition of three natural gas-fired electrical generation facilities in northern California totaling 523 MW (collectively, the San Joaquin Facilities), including the 330-MW Tracy, the 97-MW Hanford and the 96-MW Henrietta facilities in November 2015;
- Completed 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 January 2015;

- Began construction of the 198 Mmcf/d Townsend shallow-cut processing facility (Townsend Facility), which is on track to be in service by mid-2016. Completed construction of the 25 km gas gathering line and started work on two liquids egress lines and a truck terminal on the Alaska highway;
- Signed a sublease and related agreements with Ridley Terminals Inc. (Ridley Terminals) to develop, build, own and operate a proposed propane export terminal (the Ridley Island Propane Export Terminal), which is to be located on a portion of land leased by Ridley Terminals from the Prince Rupert Port Authority (PRPA) on Ridley Island near Prince Rupert, British Columbia;
- Continued the development of a liquids separation facility near Fort St. John, British Columbia;
- Increased the number of shipments from the Ferndale liquefied petroleum gas (LPG) terminal (the Ferndale Terminal), which is owned by Petrogas and operated by AltaGas, from 8 ships in 2014 to 13 ships in 2015;
- Achieved commercial operations at the 66-MW McLymont Creek Hydroelectric Facility (McLymont) in October 2015;
- Declared the 15-MW Cogeneration III (Cogeneration III) at the Harmattan extraction plant (Harmattan) in-service in the fourth quarter 2015; and
- Received regulatory approval of the Main Replacement Program (MRP) at SEMCO Gas resulting in increased rates.

2015 FINANCIAL HIGHLIGHTS (1)

- Normalized EBITDA was $582 million in 2015, a 7 percent increase compared to $546 million in 2014;
- Normalized funds from operations was $470 million ($3.41 per share) in 2015, compared to $472 million ($3.72 per share) in 2014;
- Net revenue was $996 million in 2015, compared to $1 billion in 2014;
- Net debt was $3.9 billion as at December 31, 2015, compared to $2.9 billion as at December 31, 2014;
- Debt-to-total capitalization ratio was 48 percent as at December 31, 2015, compared to 45 percent as at December 31, 2014;
- On April 14, 2015, issued US$125 million senior unsecured medium-term notes (MTNs). The notes carry a floating coupon rate of three month LIBOR plus 0.85 percent and mature on April 17, 2017;
- On April 30, 2015, AltaGas announced an increase in its dividend of $0.0125 per common share per month to $0.160 and on September 21, 2015, AltaGas announced an increase in its dividend of $0.005 per common share per month to $0.165, which collectively represent a 12 percent increase in the dividend over 2014;
- On September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million;
- On November 23, 2015, AltaGas closed a public offering of 8,000,000 Cumulative Redeemable 5-Year Minimum Rate Reset Preferred Shares, Series I, at a price of $25.00 per Series I Preferred Share for aggregate gross proceeds of $200 million; and
- On December 4, 2015, AltaGas extended the maturity of its $1.4 billion syndicated credit facility by one year to December 15, 2019.

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

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 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 gas processing. The currently depressed commodity market conditions are accelerating this trend as producers seek to conserve capital and monetize non-core assets. AltaGas seeks to move natural gas and natural gas liquids (NGL or NGLs) 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 its ownership interest in Petrogas and the Ferndale Terminal, and through its proposed Ridley Island Propane Export Terminal currently under development. AltaGas is focused on developing and operating larger gas infrastructure projects. On February 2, 2016, AltaGas announced 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. The sale is part of a plan to focus resources on operating and optimizing AltaGas' larger plants and developing larger scale opportunities as part of the northeast British Columbia strategy.

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 natural gas-fired power generation, which is expected to provide critical load balancing across North America, as significant nuclear and coal-fired power generation is expected to be decommissioned over the next decade and be replaced by renewable power and natural gas-fired power generation. AltaGas is positioned to take advantage of this opportunity.

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.

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 $1.7 billion in projects over the last few years, which provides a significant competitive advantage. Cost efficiency and strong operating performance are the drivers for increasing value as the Corporation continues to build out its portfolio of assets. Key initiatives continue to increase proficiency in managing costs and include changes to cost tracking systems and implementing best practice procurement strategies.

Consistent with its mandate of overseeing and directing the Corporation's strategic direction, AltaGas' Board of Directors (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 Canadian producers. 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 coast. 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 development of the proposed 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 Energy Corporation, the largest LPG importer in Japan.

There has been an increase in the demand for clean sources of power to reduce greenhouse gas emissions due to increased regulations. Such regulations necessitate significant development of natural gas-fired and renewable generation. AltaGas is positioned to take advantage of this opportunity. In California, the California Independent System Operator (CAISO) has stated that up to 13,000 MW of fast ramping flexible capacity is required to meet the needs of the current 33 percent Renewable Portfolio Standard (RPS) of California by 2020. In October 2015, the State of California amended the RPS, increasing the RPS standard to a 50 percent renewables target by 2030. The CAISO has yet to announce the anticipated additional generation required to meet the 50 percent RPS. 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 and re-contracting. AltaGas is well positioned in northern California with the acquisition of the San Joaquin Facilities and Ripon in 2015. In southern California, AltaGas is well positioned at the convergence of transmission lines with multiple options available for contractual counterparties. The Blythe Energy Center along with potential expansions of Blythe II and Blythe III 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 Authority (WAPA). Further development and expansion opportunities could arise if CAISO becomes the Regional Transmission Organization incorporating Nevada and Arizona.

Within the Utilities segment, growth is expected through expansion of the existing distribution systems to acquire new customers; acquisition of new franchises when it is cost effective or strategic to do so; fuel switching as abundant natural gas provides a clean low-cost energy alternative and investment in existing distribution systems to ensure safe, reliable service for AltaGas' customers. Also, there is a natural gas storage opportunity currently under construction in Nova Scotia to 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 maintain ready access to capital markets.

A key element of the Corporation's stable business model is mitigating its exposure to certain market price risks as well as volume risk. In addition to its diversification strategy, the Corporation has developed risk management processes that mitigate earnings volatility from commodity price risk and volume risk. AltaGas proactively hedges interest rates, foreign exchange rates and commodity price exposures 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 US 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 2015 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 $3 billion in assets five years ago to total assets of over $10 billion at the end of 2015. In the last five years, the Corporation has reported a 6 percent and 7 percent compound annual growth rate in normalized EBITDA and dividends per share, respectively. AltaGas delivers an effective balance between yield and growth.

AltaGas continues to drive its strategy to grow its highly contracted, clean power generation portfolio. As at December 31, 2015, approximately 62 percent and 21 percent of total generation capacity came from gas-fired and renewables sources, respectively. In 2015, AltaGas acquired 687 MW of western U.S. natural gas-fired power generation through two acquisitions: 164 MW in January through the acquisition of Ripon, Pomona and Brush II, followed by 523 MW in November through the acquisition of the San Joaquin Facilities. These acquisitions were important additions to AltaGas' business by establishing the Corporation's presence in Northern California and strengthening AltaGas' overall California market position.

The Corporation safely commissioned McLymont in the fourth quarter of 2015. Commercial operation at McLymont represented the final phase of the $1 billion Northwest Hydro Projects (the Northwest Hydro Facilities), which also include the 195-MW Forrest Kerr Hydroelectric Facility (Forrest Kerr) and the 16-MW Volcano Creek Hydroelectric Facility (Volcano), both of which were commissioned in the second half of 2014. The Corporation successfully completed the first full year of operations at Forrest Kerr, and implemented numerous operational improvements to enhance efficiency and reliability. In the fourth quarter of 2015 Cogeneration III was declared in service. Through a combination of strategic acquisitions and the completion of organic projects, AltaGas delivered over 50 percent growth in power generation capacity in 2015, providing over 80 percent of total generation capacity from clean energy sources, including hydro, wind, biomass and gas-fired. Over 90 percent of AltaGas' clean power generation portfolio is underpinned by long-term contracts.

AltaGas continues to progress its integrated northeast British Columbia strategy on several different fronts. Construction is approximately 75 percent complete at the Townsend Facility, which is underpinned by take-or-pay commitments from Painted Pony Petroleum Ltd. (Painted Pony). In addition to the Townsend Facility, AltaGas initiated two other related projects in 2015. The first is a 25 km gas gathering line, which will connect the Blair Creek field gathering area to the Townsend Facility. Painted Pony has reserved all of the firm service under a 20-year take-or-pay agreement. The second project consists of two liquids egress lines totaling approximately 30 km, and a truck terminal on the Alaska Highway. The lines will connect the Townsend Facility to the truck terminal and have a combined initial capacity of 60,000 bbls/day. Also in 2015, AltaGas began development of a liquids 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 to Canada's West Coast and North American markets. Please refer to the *Growth Capital* section in this MD&A for further details regarding these projects.

AltaGas strives to meet producer needs for new markets and higher netbacks by advancing energy exports projects. AltaGas signed a sublease and related agreements with Ridley Terminals for the development of a proposed propane export terminal which is located on a portion of land leased by Ridley Terminals from the PRPA on Ridley Island near Prince Rupert, British Columbia. This proposed propane export facility is expected to ship up to 1.2 million tonnes per annum. AltaGas is working towards a final investment decision (FID) in 2016. Please refer to the *Growth Capital* section in this MD&A for further details regarding this project.

Across the five separate utility franchises throughout North America, AltaGas continues to focus on safely and reliably delivering customers clean, affordable energy. In 2015 AltaGas achieved customer growth across all utilities, and grew rate base by expanding its existing infrastructure through system upgrade programs and organic growth opportunities. SEMCO Gas also obtained approval of its MRP from the Michigan Public Service Commission (MPSC). In addition, in September 2015, the Regulatory Commission of Alaska accepted a stipulation to resolve all matters for ENSTAR's rate case, including a rate increase. ENSTAR also agreed to file a 2016 rate case with a 2015 test year.

In 2015, the Corporation enhanced its financial strength and flexibility through a combination of internally-generated cash flows, the dividend reinvestment program (DRIP), and the issuance of approximately $650 million of equity and long-term debt. During the year, AltaGas issued approximately $300 million of common shares, $200 million of preferred shares and US$125 million of medium-term notes. In addition, on December 4, 2015, AltaGas extended the maturity of its $1.4 billion syndicated credit facility by one year to December 15, 2019. AltaGas maintained sufficient liquidity and a strong balance sheet throughout the year and exited 2015 with approximately $987 million of available credit facilities, cash of $293 million, and debt-to-total capitalization of 48 percent. AltaGas entered 2016 well positioned to fund its growth capital and to take advantage of growth opportunities when they arise.

During 2015, the Board of Directors approved two dividend increases for a total increase of 12 percent from $1.77 per share to $1.98 per share on an annualized basis. The dividend increases reflect the success of AltaGas' recent asset additions across all business segments, as well as the stability and sustainability of its cash flows.

2016 OUTLOOK

AltaGas currently expects to deliver overall normalized EBITDA growth of approximately 20 percent in 2016 compared to 2015. The Power and Utilities segments are expected to report higher normalized EBITDA and operating income, while normalized EBITDA and operating income from the Gas segment are expected to remain roughly flat compared to 2015. The most significant driver of normalized EBITDA growth is a full year contribution from the San Joaquin Facilities acquired on November 30, 2015. 2016 will also be the first year that all three Northwest Hydro Facilities provide a full year contribution as McLymont entered commercial service in the fourth quarter of 2015. AltaGas' integrated northeast British Columbia gas strategy is expected to add additional EBITDA in 2016 with a partial year contribution from the first phase of the Townsend Facility entering commercial operations mid-year. AltaGas' 2016 normalized EBITDA growth projections assume no near-term recovery in commodity prices. If commodity prices recover, AltaGas is well positioned to deliver additional normalized EBITDA growth. The Utilities segment is expected to report increased normalized EBITDA in 2016 driven by rate base and customer growth. The overall forecasted growth in normalized EBITDA includes lower commodity hedge gains compared with 2015 as well as higher operating and administrative costs due to new assets placed into service. Normalized operating income for 2016 is expected to be higher due to the factors noted above, partially offset by higher depreciation and amortization expense on new assets.

AltaGas currently expects normalized funds from operations to grow by approximately 15 percent in 2016, driven by the factors noted above for normalized EBITDA, partially offset by higher financing costs related to new assets acquired as well as new assets in service, and higher current tax expenses.

In the Power segment, increased earnings are expected to be driven by the San Joaquin Facilities and a full-year contribution from McLymont. The earnings and cash flows from the Northwest Hydro Facilities are expected to be seasonally stronger beginning in the second quarter through early in the fourth quarter, and seasonally weaker in the first quarter based on normal water flow patterns. Actual seasonal water flows will vary with rainfall and snowpack 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 2016 driven by rate base and customer growth. SEMCO Gas expects approximately $8 million of margin in 2016 as a result of a full year contribution of its MRP. The Regulatory Commission of Alaska accepted a stipulation filed by ENSTAR in 2015, which included a rate increase (annualized) of approximately US$4 million as well as an additional interim and refundable rate increase (annualized) of approximately US$2 million. 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 normalized weather, earnings at the utilities would be affected.

In the Gas segment, additional earnings are expected to be driven by a partial year contribution from the first phase of the Townsend Facility, higher earnings from Petrogas, and the absence of turnarounds at the Harmattan and Younger extraction plants and are expected to be offset by lower commodity hedge gains. AltaGas expects NGL prices to remain depressed and anticipates that the extraction of certain NGL at some of its facilities will remain uneconomic resulting in reinjection. Based on current commodity prices, AltaGas estimates an average of approximately 2,000 to 3,000 Bbls/d will be exposed to frac spread in 2016. Given weak commodity prices, AltaGas does not expect to enter into frac hedges for 2016 at this time.

On February 2, 2016, AltaGas announced the sale of certain non-core natural gas gathering and processing assets located primarily in central and north central Alberta, totaling approximately 490 Mmcf/d of gross licensed natural gas processing capacity for total consideration of $30 million of cash and 43.7 million common shares of Tidewater Midstream and Infrastructure Ltd. The sale is part of AltaGas' strategy to focus on larger scale opportunities in the Gas segment that support the overall northeast British Columbia strategy. Subject to customary closing conditions being satisfied, the transaction is expected to close in the first quarter of 2016. These non-core gas assets represented less than 2 percent of AltaGas' expected 2016 normalized EBITDA.

If the US dollar remains strong compared with 2015, the EBITDA and operating income reported for the U.S. assets will benefit accordingly in 2016. Some of this benefit is offset by US dollar denominated depreciation, interest on US dollar denominated debt, dividends on US dollar denominated preferred shares and U.S. income tax expense.

The Alberta government announced its Climate Leadership Plan on November 22, 2015, with details of the final strategy still to be developed. The complete impact of the Climate Leadership Plan to AltaGas is yet to be determined. The key areas include: phasing out coal-generated electricity by 2030, developing more renewable energy through competitive procurement processes, a recommendation to phase out the current Specified Gas Emitters Regulation (SGER), an emissions intensity-based carbon pricing program by 2018 with a new Carbon Competitiveness Regulation (CCR), which is based on an emissions performance standard, and assessing opportunities for new gas-fired generation to support grid reliability. 2016 normalized EBITDA projections for the Power segment include no contributions from coal-fired generation.

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 2016.

Factor	Increase or decrease	Impact on normalized EBITDA *($ millions)*
Alberta electricity prices	$1/Mwh	2
Natural gas liquids fractionation spread[(1)]	$1/Bbl	1
Degree day variance from normal - Canadian utilities[(2)]	5 percent	1
Degree day variance from normal - U.S. utilities[(3)]	5 percent	4
Change in CAD per US$ exchange rate	$0.05	14

(1) Based on no 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.

GROWTH CAPITAL

Based on projects currently under review, development, or construction, AltaGas expects capital expenditures in the range of $550 to $650 million for 2016. Gas and Power maintenance capital is expected to be less than $40 million of the total expected capital expenditures. A large portion of growth capital expenditures are discretionary and AltaGas has the flexibility to adjust the pace of spending at its option. The Corporation continues to focus on enhancing productivity and streamlining businesses, including the disposition of smaller non-core assets.

AltaGas' 2016 committed capital program is largely funded through internally-generated cash flow and DRIP, with the balance through available credit facilities.

Townsend Gas Processing Facility

The Townsend Facility is a 198 Mmcf/d shallow-cut gas processing facility located approximately 100 km north of Fort St. John and 20 km southeast of AltaGas' Blair Creek Facility. Painted Pony has reserved all of the firm capacity under a 20-year take-or-pay agreement. The estimated cost for the Facility and associated infrastructure is approximately $325 to $350 million, and includes the plant, sales gas line, improvements to site, local roads and the Alaska Highway, as well as additional compression. Construction of the Townsend Facility is progressing ahead of schedule and is approximately 75 percent complete. The facility is on track to be in service by mid-2016.

Incremental to the Townsend Facility are two other related projects. The first is a 25 km gas gathering line, which is now substantially complete and expected to cost approximately $38 million (versus $43 million original cost expectation). This pipeline connects the Blair Creek field gathering area to the Townsend Facility. Painted Pony has reserved all of the firm service under a 20-year take-or-pay agreement. The second project consists of two liquids egress lines totaling approximately 30 km, and a truck terminal on the Alaska Highway, which are estimated to cost approximately $80 to $90 million. The lines will connect the Townsend Facility to the truck terminal and are expected to have a combined initial capacity of up to 60,000 bbls/day. The pipelines have been approximately 30 percent constructed. Construction of the truck terminal is scheduled to occur in the second to third quarter of 2016. Long-lead equipment is on order, and site clearing has commenced. Painted Pony is expected to reserve all firm liquids capacity under a 20-year take-or-pay agreement.

Northeast British Columbia Liquids Separation Facility

AltaGas has begun development of a liquids separation and handling facility near Fort St. John, British Columbia, which will be connected to existing AltaGas infrastructure in the region, including the proposed Ridley Island Propane Export Terminal, and will serve producers in the Montney region. Current specifications are expected to include up to 20,000 bbls/d of liquids separation and up to 20,000 bbls/d of stabilized condensate handling. The facility is estimated to cost approximately $130 to $140 million. The site is well connected by rail to Canada's West Coast and North American markets. A front-end engineering and design (FEED) study was substantially completed in January 2016 and further capital optimization opportunities are currently being reviewed. Consultations with First Nations and key stakeholders continue, and AltaGas expects to receive permits to reach FID in 2016.

Ridley Island Propane Export Terminal

AltaGas signed a sublease and related agreements with Ridley Terminals to develop, build, own and operate the proposed Ridley Island Propane Export Terminal located near Prince Rupert, British Columbia on a portion of lands leased by Ridley Terminals from the Prince Rupert Port Authority. The proposed Ridley Island Propane Export Terminal is estimated to cost approximately $400 to $500 million and is to be designed to ship up to 1.2 million tonnes of propane per annum. It will be built on a brownfield site with a history of industrial development, connections to existing rail lines and an existing marine jetty with deep water access to the Pacific Ocean. Propane from British Columbia and Alberta natural gas producers will be transported to the facility using the existing CN rail network.

Preliminary engineering has been completed and a FEED study is in progress. The process of engaging and consulting with First Nations, communities, government, and environmental and regulatory authorities is underway. AltaGas is working towards reaching a FID in 2016. Commercial operation to commence propane exports is targeted for 2018, subject to First Nations consultations and necessary approvals. On February 11, 2016, AltaGas filed an application with the National Energy Board (NEB) for a 25-year propane export license.

Douglas Channel Liquefied Natural Gas (DC LNG) Project

The DC LNG Consortium, comprised of AltaGas Idemitsu Joint Venture Limited Partnership (AIJVLP), EDF Trading Limited (EDFT) and EXMAR NV (EXMAR), agreed in the first quarter of 2016 to halt development of the DC LNG Project due to adverse economic conditions and worsening global energy price levels.

Alton Natural Gas Storage Project

AltaGas has commenced work on the Alton Natural Gas Storage project located near Truro, Nova Scotia, which is expected to provide up to 10 Bcf of natural gas storage capacity. On January 21, 2016 the Government of Nova Scotia announced that a number of remaining permits will be issued and following receipt of such permits, construction is expected to continue in 2016 with storage service expected to commence in 2019. AltaGas has entered into a long-term storage agreement with Heritage Gas. Heritage Gas received regulatory approval from the Nova Scotia Utility and Review Board in 2015 for the recovery of the costs of the storage service and the method of recovery.

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 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, 2015, AltaGas owned 1.6 Bcf/d of extraction processing capacity and 1.4 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 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 the energy export projects.

Specifically, the Gas segment includes:

- Interests in six NGL extraction plants with net licensed inlet capacity of 1.6 Bcf/d. The extraction assets provide stable fixed-fee or cost-of-service type revenues and margin based revenues. Effective January 1, 2016, AltaGas acquired the remaining 51 percent interest in Edmonton Ethane Extraction Plant (EEEP), increasing the total net licensed inlet capacity to 1.8 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, and is the third largest producer of NGL in the WCSB;
- Four natural gas transmission systems with combined transportation capacity of approximately 0.6 Bcf/d and four NGL pipelines with combined capacity of 189,300 Bbls/d. The transmission assets provide stable take-or-pay based revenues. In 2014, Nova Chemicals Corporation (Nova Chemicals) provided notice that it intends to exercise its option to purchase the Ethylene Delivery Systems (EDS) and Joffre Feedstock Pipeline (JFP) transmission assets effective March 31, 2017;
- Approximately 70 gathering and processing facilities in Western Canada and a network of approximately 6,100 km of gathering and sales lines that gather gas upstream of processing facilities and deliver natural gas into downstream pipeline systems that feed North American natural gas markets as at December 31, 2015. 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. On February 2, 2016, AltaGas announced 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;
- 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 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-third ownership in Petrogas, a leading North American integrated midstream company, with an extensive logistics network consisting of over 1,700 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 will be constructed and operated by AltaGas, where AltaGas markets Painted Pony's gas and liquids;
- Development of the proposed Ridley Island Propane Export Terminal in British Columbia; and
- Development of the liquids separation and handling facility near Fort St. John, British Columbia.

Please refer to the *Growth Capital* section in this MD&A for further details regarding the Townsend Facility, the proposed Ridley Island Propane Export Terminal, the liquids separation and handling facility near Fort St. John, British Columbia, 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;
- Maximize profitability of existing facilities by increasing capacity, utilization and efficiency;
- Mitigate volume risk through contractual structures, redeployment of equipment and expansion of geographical reach;
- Coordinate between facilities, business segments and product lines to improve efficiencies and maximize profits;
- Expand into new natural gas infrastructure markets such as regional liquefied natural gas (LNG); and
- Maintain strong social license with local communities, First Nations, governments, and regulatory bodies.

In recent years, the WCSB has changed from a maturing basin to one capable of sustainable long-term growth via new low cost sub-plays such as the Montney basin. Despite the currently depressed commodity market conditions, AltaGas remains confident that the long-term demand for natural gas, combined with improvements in exploration, drilling and completion technology, will support the long-term viability of the WCSB. The emergence of unconventional gas plays in the WCSB such as the Montney and Duvernay, as well as increased focus on horizontal multi-fracturing technology have resulted in abundant natural gas supply and associated liquids. Market demand, including the demand generated from the potential LPG and LNG export projects on the West Coast of North America, provides significant growth opportunities in the Corporation’s Gas segment in the long-term. 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 capacity. 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.

The currently depressed commodity market conditions are accelerating a trend of producers seeking to conserve capital and monetize non-core assets. AltaGas is well positioned to build or acquire gathering and processing infrastructure from, or on behalf of, producers. 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 and its related infrastructure is an example of AltaGas' ability to capitalize on energy infrastructure growth opportunities while providing a fully-integrated midstream service offering to its customers. The Gordondale Gas Plant and the Blair Creek Facility are meeting liquids extraction needs in the Montney area as producers seek to increase netbacks by capitalizing on liquids-rich gas in this prolific area. The Gordondale and Blair Creek facilities are underpinned by take-or-pay contracts, which provide stable cash flows. 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. 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 proposed Ridley Island Propane Export Terminal near Prince Rupert, British Columbia currently under development 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 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 long-term contracts with the exception of the Alberta assets and Pomona. 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, 2015, the Power segment included 2,041 MW of power generation capacity from hydro, gas-fired, coal-fired, wind, and biomass assets, along with an additional 1,253 MW of assets under development.

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 and the 44-MW Pomona, all of which are located in California, and the 70-MW Brush II in Colorado. All facilities are under PPAs with creditworthy utilities except Pomona. A further 1,163 MW of gas-fired generation is under development;
- 353 MW of coal-fired generating capacity in Alberta through the Sundance B PPA until December 31, 2020. Power is sold into the Alberta spot market and AltaGas employs an economic hedging strategy to mitigate the exposure to Alberta spot power prices;
- 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 plants capacity in Alberta, with a further 90 MW of peaking plant capacity under development; and
- 35 MW of biomass generation in the United States. The plants have long-term PPAs with strong counterparties.

In northern California, the Corporation is focused on owning generating assets in locally constrained areas near load pockets as local resource adequacy needs result in more opportunities for expansion and re-contracting. On November 30, 2015, AltaGas acquired three northern California 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. AltaGas is currently in the preliminary stages of permitting to increase generation capacity at Ripon.

In southern California, the existing 507-MW Blythe Energy Center is currently operating under a long-term PPA with Southern California Edison (SCE) until July 31, 2020, serving the CAISO market. The opportunities for growth include Blythe Energy Center's unique position to potentially serve both CAISO and the WAPA markets. 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 interconnects the 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 and is also connected to the El Paso gas supply. The transmission line is capable of transmitting 1,100 MW and has excess capacity to meet future load growth. In 2014, AltaGas acquired a fully permitted and shovel-ready site directly adjacent to the existing Blythe Energy Center, known as the Sonoran Energy Project or Blythe II, and 76 acres of land north of the current Blythe Energy Center to support further expansion opportunities (Blythe III). Both projects have the potential to contract with multiple creditworthy utilities and regional municipalities in California and adjacent states. The development of both projects could potentially more than triple AltaGas' current generating capacity in the vicinity of the Blythe Energy Center over the medium and long term. In addition, AltaGas acquired Pomona in early 2015, which is strategically located in the Los Angeles basin load pocket. As development activities advance, the PPA for Pomona was amended at the end of 2015 with no fixed capacity payments in order to facilitate the transition of this facility on an interim basis to the merchant market. AltaGas is currently in the preliminary stages of permitting the site for repowering Pomona with more efficient technology and plans to bid into a competitive solicitation process with a load serving entity.

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 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 are 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. Both biomass facilities have long-term PPAs.

In Alberta, the Corporation employs a power hedging strategy which is designed to balance market and operational risks related to the Alberta generation portfolio. AltaGas also sells power to Commercial and Industrial (C&I) end-users in Alberta, providing further earnings stability. 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 and a source of liquidity that has decreased in the wholesale market.

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;
- 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 III, as well as seeking to re-contract and/or extend existing PPAs for operating assets at beneficial terms;
- Execute power hedges to balance operational and market risk and explore opportunities for new natural gas-fired and renewable power generation in Alberta; and
- Maintain strong social license with local communities, First Nations, governments, and regulatory bodies.

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. Although coal-fired generation is still the largest fuel source for power generation in North America, it is decreasing in market share for environmental and economic reasons. Low cost natural gas has resulted in 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 fossil 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, hydroelectric and wind. Both the Canadian federal government's stated policy to have coal-fired generators retire at the end of their useful economic lives and the Alberta government's proposed Climate Leadership Plan necessitates new natural gas-fired and renewable generation. 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 and Brush II 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 560,000 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 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 2015, SEMCO Gas had approximately 300,000 customers. Of these customers, approximately 84 percent are residential. In 2015, SEMCO Gas experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favourable price of natural gas. The rate base at year end was approximately US$477 million. In 2015, the approved regulated ROE for SEMCO Gas was 10.35 percent on 50 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$0.8 million as its 2014 EO plan performance incentive.

ENSTAR and CINGSA

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 2015, ENSTAR had approximately 140,000 customers including residential, commercial and transportation and of these customers, approximately 91 percent are residential. In 2015, ENSTAR experienced customer growth of approximately 1 percent reflecting growth in the franchise areas and customer conversions with the favourable price of natural gas. The rate base at year end was approximately US$288 million for ENSTAR and US$86 million for CINGSA (SEMCO's 65 percent share).

ENSTAR and CINGSA are regulated by the Regulatory Commission of Alaska (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.

ENSTAR filed a base rate case in September 2014. In July 2015, the parties to ENSTAR's rate case proceeding reached an agreement in principle to settle the case and a stipulation was filed with the RCA in August 2015, which was accepted by the RCA in September 2015. As part of the stipulation, ENSTAR agreed to a 2016 rate case to be filed by June 1, 2016, with a 2015 test year. As part of the order accepting the stipulation, the RCA indicated that it intended to fully adjudicate the new rate case. The stipulation also granted a permanent rate increase effective October 1, 2015 of approximately 2.2 percent over the 1 percent interim and refundable rate increase 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 increases that were previously approved, which went into effect on November 1, 2014. Finally, the stipulation granted another interim and refundable rate increase of approximately 0.8 percent to go into effect on January 1, 2016, until resolution of the 2016 rate case.

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 November 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 of approximately 2,200 pounds per square inch (psi). Following extensive analysis, CINGSA has determined that the pocket of found gas it discovered, totaling approximately 14.5 Bcf, is not necessary to provide pressure support for CINGSA's storage operations. In January 2015, CINGSA filed a tariff revision with the RCA to permit and account for the sale of a portion of the found gas.

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.

AltaGas Utilities Inc.

AUI owns and operates a regulated natural gas distribution utility in Alberta. At the end of 2015, AUI served approximately 78,000 customers. AUI's customers are primarily residential and small commercial consumers located in smaller population centers or rural areas of Alberta. Customer growth in 2015 was 2 percent and AUI's rate base at year end was approximately $261 million.

AUI is currently operating under a revenue cap per customer formula under PBR, a regulation that commenced with Alberta electric and natural gas distribution companies effective January 1, 2013, in place of the existing cost-of-service regulatory system. The PBR framework is intended to incentivize utilities to be more efficient. The initial PBR term lasts for five years (2013-2017) and the Alberta Utilities Commission (AUC) will make a determination at the end of the initial term as to how it will proceed for future years.

For 2015 and 2014, AUI's approved placeholder for regulated ROE was 8.3 percent on a prescribed capital structure of 42 percent equity and 58 percent debt. The 2016-2017 Generic Cost of Capital (GCOC) proceeding is in progress and expected to be completed in 2016. The proceeding will establish the return on equity and capital structures for all AUC-regulated utilities for 2016, 2017 and, possibly, future years. In the interim, the AUC has approved continued use of the 2013-2015 ROE of 8.3 percent as a placeholder.

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 2015, PNG served approximately 41,300 customers. Customer growth in 2015 was 1.5 percent, which is strong for PNG's mature network and reflective of the economic activity in this region. Approximately 87 percent of PNG's total customers are residential. PNG's rate base at year end was approximately $203 million.

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. For 2015, PNG did not file its annual revenue requirement application and maintained customer rates at the 2014 approved levels.

In November 2015, PNG filed its 2016 and 2017 revenue requirements application with the BCUC for all its divisions. The applications sought approvals to increase rates on an interim basis effective January 1, 2016 at the levels set forth in the applications. A written regulatory process has been established and the BCUC's final decision on new delivery rates for both 2016 and 2017 is expected in the third quarter of 2016.

On March 25, 2014, the BCUC issued its decision on the Generic Cost of Capital (GCOC) Stage 2 proceeding. The approved common equity ratio for PNG West and PNG(N.E.) TR division was set at 46.5 percent and the approved common equity ratio for PNG(N.E.) FSJ/DC division was set at 41 percent. The BCUC also established an equity risk premium of 75 basis points (bps) for PNG West and PNG(N.E.) TR division and an equity risk premium of 50 bps for PNG(N.E.) FSJ/DC division. This resulted in an allowed ROE of 9.50 percent for PNG West and PNG(N.E.) TR and 9.25 percent for PNG(N.E.) FSJ/DC effective January 1, 2013. These common equity ratios and allowed ROEs were also in effect for 2015. In October 2015, FortisBC Energy Inc., the Benchmark Utility, filed an application for its Common Equity Component and Return on Equity for 2016 with BCUC. BCUC's decision is expected in the third or fourth quarter of 2016 and will impact PNG's common equity component and allowed ROE for 2016 onwards.

On January 20, 2015, PNG received BCUC approval to assign, novate, and amend a Gas Transportation Service Agreement (GTSA) with EDFT, a member of DC LNG Consortium, that provides an option to contract for 80 Mmcf/d of the existing capacity on the Western System. On October 15, 2015, PNG also received BCUC approval on its Application for a Certificate of Public Convenience and Necessity to Construct and Operate an Interconnecting Pipeline between Kitimat and Douglas Channel to facilitate servicing the GTSA, EDFT and the DC LNG Project. In the first quarter of 2016, the DC LNG Consortium halted development of the DC LNG Project. Please refer to the *Growth Capital* section of the MD&A for more details.

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. At the end of 2015, Heritage Gas had approximately 6,300 customers. Customer growth in 2015 was 9 percent, reflecting Heritage Gas' relatively new presence in the Nova Scotia energy market. Heritage Gas has a relatively balanced mix of residential, small commercial and large commercial customers. Heritage Gas' rate base at year end was approximately $277 million. For 2015 and 2014, 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. Heritage Gas is regulated by the Nova Scotia Utility and Review Board (NSUARB). Heritage Gas has not applied for updated rates for 2015 and continues to assess if it will apply for a change to rates for 2016 or later.

In 2012, Heritage Gas began to develop a Compressed Natural Gas (CNG) trucking distribution system, which will allow customers who are not connected through the traditional pipeline distribution infrastructure to gain access to natural gas. Operations commenced in May 2013 and to date the business has been developed and operated as non-regulated. In December 2014, Heritage Gas received approval from the NSUARB to expand its regulated operations into Antigonish County. Heritage Gas intends to serve this new market using CNG, which would result in a portion of the CNG business being subject to rate-based regulation once the Antigonish distribution system is in operation.

Current propane and oil commodity prices have made the energy market serving small commercial customers extremely competitive with some customers choosing to adopt alternative fuels to natural gas, or implement dual fuel options. Therefore, natural gas storage service is critical to ensuring security of gas supply for Heritage Gas' customers and to reducing natural gas price volatility. In October 2014, Heritage Gas negotiated a long-term Precedent Agreement with Alton Natural Gas Storage LP (Alton), a wholly-owned subsidiary of AltaGas, which has been granted NSUARB approval to construct an underground hydrocarbon storage facility in Nova Scotia. In December 2014, Heritage Gas submitted an application to the NSUARB for approval of the natural gas storage costs and the method of recovery and allocation of those costs. On June 4, 2015 Heritage Gas received the NSUARB's Decision approving Heritage Gas' Application for the treatment, and the recovery, of natural gas storage service costs related to the proposed Alton Natural Gas Storage Facility. The Alton storage service is anticipated to provide benefits to Heritage Gas and its customers in the form of security of gas supply, enhanced reliability and delivery of natural gas during the peak heating season, as well as reduced natural gas price volatility. AltaGas currently expects storage service to commence in 2019. See *Growth Capital* section of this MD&A for further details.

In October 2014, Heritage Gas signed a Precedent Agreement with Spectra Energy on the Atlantic Bridge Project, on the Algonquin Gas Transmission (AGT) pipeline system. The contract, which is backed by a guarantee issued by AltaGas, is a 15-year commitment that provides Heritage Gas an opportunity to diversify suppliers and provide access to other supply basins. The expected in-service date is late 2017.

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 has 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. Effective August 8, 2014, Inuvik Gas extended its gas distribution franchise with the town of Inuvik for a period of 10 years. AltaGas and the other shareholders in Inuvik Gas continue to pursue alternative long-term energy sources for Inuvik Gas.

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 community and regulatory relationships while ensuring fair returns to shareholders;
- Acquire new franchises when the opportunities arise; and
- Maintain strong social license with local communities, First Nations groups, governments, and regulatory bodies.

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 Heritage Gas seeing significant growth to date, while mature utilities such as AUI and SEMCO Gas see more moderate growth rates, which are generally tied closely to the economic growth of the respective franchise regions.

CONSOLIDATED FINANCIAL REVIEW

($ millions)	Three Months Ended December 31 **2015**	2014	Years Ended December 31 **2015**	2014
Revenue	**580**	667	**2,193**	2,406
Net revenue[1]	**216**	286	**996**	1,019
Normalized operating income[1]	**111**	105	**359**	366
Normalized EBITDA[1]	**173**	155	**582**	546
Net income (loss) applicable to common shares	**(54)**	10	**10**	96
Normalized net income[1]	**56**	48	**140**	165
Total assets	**10,100**	8,396	**10,100**	8,396
Total long-term liabilities	**4,949**	4,058	**4,949**	4,058
Net additions to property, plant and equipment	**732**	144	**1,150**	503
Dividends declared[2]	**72**	59	**260**	215
Cash flows				
Normalized funds from operations[1]	**159**	154	**470**	472

($ per share, except shares outstanding)	Three Months Ended December 31 **2015**	2014	Years Ended December 31 **2015**	2014
Normalized EBITDA[1]	**1.19**	1.16	**4.22**	4.31
Net income (loss) per common share - basic	**(0.37)**	0.08	**0.07**	0.75
Net income (loss) per common share - diluted	**(0.37)**	0.08	**0.07**	0.74
Normalized net income[1]	**0.38**	0.36	**1.02**	1.30
Dividends declared[2]	**0.50**	0.44	**1.89**	1.69
Cash flows				
Normalized funds from operations[1]	**1.09**	1.15	**3.41**	3.72
Shares outstanding - basic (millions)				
During the period[3]	**146**	134	**138**	127
End of period	**146**	134	**146**	134

(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 and $0.165 beginning on October 26, 2015.

(3) Weighted average.

FOURTH QUARTER 2015

The overall results for the fourth quarter of 2015 reflect the seasonally stronger quarter for the Utilities segment, the closing of the San Joaquin Facilities acquisition on November 30, 2015, and the successful commissioning of McLymont on October 28, 2015. The fourth quarter of 2015 also reflects the benefit of the strong US dollar when compared to the same quarter in 2014. However, fourth quarter results continued to be impacted by the low commodity price environment when compared to the prior year.

Normalized EBITDA for the fourth quarter of 2015 was $173 million, compared to $155 million for the same quarter in 2014. With the commissioning of McLymont, the Northwest Hydro Facilities contributed EBITDA growth of approximately $14 million compared to the fourth quarter of 2014, while the acquisition of Ripon, Pomona and Brush II in January 2015 and the acquisition of the San Joaquin Facilities on November 30, 2015 contributed approximately $11 million of normalized EBITDA. The stronger US dollar on reported results of the U.S. assets also contributed to the increase in normalized EBITDA. These increases were partially offset by record low Alberta power prices, weak frac spreads, and warmer weather experienced at certain Utilities.

Normalized funds from operations for the fourth quarter of 2015 were $159 million ($1.09 per share), compared to $154 million ($1.15 per share) for the same quarter in 2014, driven by the same factors as normalized EBITDA, partially offset by lower cash distributions from AltaGas' equity accounted investments and higher current income tax expense.

Normalized operating income for the fourth quarter of 2015 was $111 million, compared to $105 million for the same quarter in 2014, which reflects the factors noted above for normalized EBITDA partially offset by higher depreciation and amortization expense due to new assets placed into service.

Operating and administrative expense for the fourth quarter of 2015 was $120 million, compared to $114 million for the same quarter in 2014. 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, administrative costs related to establishing AltaGas' U.S. office in Dallas, Texas, and the impact of the stronger US dollar. Depreciation and amortization expense for the fourth quarter of 2015 was $59 million, compared to $47 million for the same quarter in 2014, due to the new assets placed into service. Interest expense for the fourth quarter of 2015 was $34 million, compared to $35 million for the same quarter in 2014.

Certain asset provisions totaling $125 million before tax were recorded in the fourth quarter of 2015, including a pre-tax charge of $35 million related to AltaGas' investment in common shares of Painted Pony; a pre-tax provision of $26 million against AltaGas' investment in ASTC Power Partnership (ASTC), which holds the Sundance B PPA; a pre-tax provision of $17 million on AltaGas' investment in its joint ventures with Idemitsu including in relation to the DC LNG Project; a pre-tax provision of $7 million on the DC LNG Project related to deferred lease expense; a pre-tax provision of $17 million for certain wind development projects; a pre-tax provision of $16 million for certain gas processing assets that were held for sale; a pre-tax provision of $4 million on AltaGas' one third interest in Inuvik Gas; and a pre-tax provision of $3 million on assets in the Ikhil Joint Venture. These asset provisions compare to the $70 million provision taken in the fourth quarter of 2014 for certain non-productive gas assets.

AltaGas recorded income tax expense of $3 million for the fourth quarter of 2015, compared to a recovery of $5 million in the same quarter of 2014, mainly due to charges to income in the fourth quarter of 2015 that did not attract tax recoveries.

Normalized net income was $56 million ($0.38 per share) for the fourth quarter of 2015, compared to $48 million ($0.36 per share) reported for the same quarter in 2014. The increase in normalized net income was primarily due to the increase in normalized operating income as discussed above, partially offset by higher income tax expense.

Net loss applicable to common shares for the fourth quarter of 2015 was $54 million ($0.37 per share), compared to net income applicable to common shares of $10 million ($0.08 per share) for the same quarter in 2014. Net loss applicable to common shares for the fourth quarter of 2015 was normalized for after-tax amounts related to transaction costs related to acquisitions, development costs related to energy export projects, provisions on assets and on investments accounted for by the equity method, unrealized gain on risk management contracts, and loss on long-term investments. In the fourth quarter of 2014, net income applicable to common shares was normalized for unrealized gain on risk management contracts, loss on long-term investments, gains on asset dispositions, provisions on assets and costs associated with early redemption of medium-term notes (MTNs).

FULL YEAR 2015

Normalized EBITDA for the year ended December 31, 2015 was $582 million, compared to $546 million in 2014. Earnings from the Northwest Hydroelectric Facilities, the stronger US dollar, growth in the Utilities segment, the Ripon, Pomona and Brush II facilities acquired in January 2015, the acquisition of the San Joaquin Facilities on November 30, 2015, and improved results for Blythe Energy Center and Energy Services are some of the key contributions to higher normalized EBITDA. These increases were partially offset by the impact of lower contributions from Alberta power assets and sales of NGL, lower earnings from Petrogas, lower fee-for-service revenues, the impact of major turnarounds at Younger and Harmattan in second quarter 2015, and warmer weather at certain of the natural gas utilities.

Normalized funds from operations for the year ended December 31, 2015 were $470 million ($3.41 per share), compared to $472 million ($3.72 per share) in 2014, reflecting the same drivers as normalized EBITDA, partially offset by lower distributions from Petrogas and higher current income tax expense. AltaGas received $54 million of dividends declared by Petrogas in 2014, whereas AltaGas received $11 million in 2015, as cash was retained by Petrogas to fund its capital program.

Normalized operating income for the year ended December 31, 2015 was $359 million, compared to $366 million in 2014, driven by the same factors as normalized EBITDA, offset by higher depreciation and amortization expense.

Operating and administrative expense for the year ended December 31, 2015 was $492 million, compared to $451 million in 2014. The increase was primarily due to new assets placed into service or acquired; administrative costs related to establishing AltaGas' U.S. office in Dallas, Texas; and the impact of the stronger US dollar. Depreciation and amortization expense for the year ended December 31, 2015 increased to $212 million compared to $173 million for the same period in 2014, mainly due to new assets placed into service and the impact of the stronger US dollar.

Interest expense for the year ended December 31, 2015 was $125 million, compared to $111 million in 2014. Interest expense increased primarily due to interest no longer being capitalized on assets placed into service in the second half of 2014 and during 2015, higher interest costs incurred on US dollar denominated debt, and higher average debt outstanding as a result of the acquisition of the San Joaquin Facilities in the fourth quarter of 2015.

AltaGas recorded income tax expense of $48 million for the year ended December 31, 2015, compared to $19 million in 2014. Income tax expense increased primarily due to higher future income taxes as a result of a 2 percent increase in the Alberta corporate income tax rate that was enacted on June 29, 2015, and charges to income that did not attract tax recoveries.

Normalized net income for the year ended December 31, 2015 was $140 million ($1.02 per share), compared with $165 million ($1.30 per share) reported in 2014. The decrease was primarily due to the lower normalized operating income as discussed above, along with higher interest, and income tax expense and preferred share dividends.

Net income applicable to common shares for the year ended December 31, 2015 was $10 million ($0.07 per share), compared to $96 million ($0.75 per share) in 2014. Total normalizing adjustments in 2015 were $130 million (2014 - $69 million). Net income applicable to common shares for the year ended 2015 was normalized for unrealized gain on risk management contracts, loss on long-term investments, provisions on assets and investments accounted for by equity method, development costs incurred for energy export projects, transaction costs related to acquisitions, and statutory tax rate changes. In 2014, net income applicable to common shares was normalized for unrealized gain on risk management contracts, loss on long-term investments, provisions on assets, costs associated with early redemption of medium-term notes, development costs incurred for energy export projects and gain on asset dispositions.

NON-GAAP FINANCIAL MEASURES

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by GAAP and may not be comparable to similar measures presented by other entities. The non-GAAP measures and their reconciliation to GAAP financial measures are shown below. These measures provide additional information that management believes is meaningful regarding 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 net revenue, normalized operating income, normalized EBITDA, normalized net income and normalized funds from operations throughout this document have the meanings as set out in this section.

Net Revenue

	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Net revenue	**$ 216**	$ 286	**$ 996**	$ 1,019
Add (deduct):				
Other loss (income)	**34**	(13)	**29**	(25)
Loss (income) from equity investments	**58**	(1)	**63**	(39)
Cost of sales	**272**	395	**1,105**	1,451
Revenue (GAAP financial measure)	**$ 580**	$ 667	**$ 2,193**	$ 2,406

Management believes that net revenue, which is revenue adjusted for other income or loss, income or loss from equity investments, and the cost of commodities purchased for sale and shrinkage, is a better reflection of performance than revenue, since changes in the market price of commodities affect both revenue and cost of sales, and equity investments are part of operating activities for the Corporation.

Normalized Operating Income

	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Normalized operating income	**$ 111**	$ 105	**$ 359**	$ 366
Add (deduct):				
Transaction costs related to acquisitions	**(2)**	(1)	**(2)**	(1)
Loss on long-term investments	**(35)**	(2)	**(34)**	(2)
Provision on assets	**(43)**	(70)	**(54)**	(119)
Provision on investments accounted for by equity method	**(47)**	—	**(47)**	—
Costs associated with early redemption of MTNs	**—**	(14)	**—**	(17)
Gain on asset dispositions	**—**	27	**—**	38
Energy export development costs	**(2)**	—	**(4)**	(2)
Unrealized gain on risk management contracts	**8**	7	**9**	5
Interest expense	**(34)**	(35)	**(125)**	(111)
Foreign exchange gain	**6**	—	**6**	—
Income tax (expense) recovery	**(3)**	5	**(48)**	(19)
Net income (loss) after taxes (GAAP financial measure)	**$ (41)**	$ 22	**$ 60**	$ 138

Normalized operating income is calculated from the Consolidated Statements of Income using net income adjusted for pre-tax unrealized gain or loss on risk management contracts, interest expense, foreign exchange gain (loss), income tax expense, transaction costs related to acquisitions, gain (loss) on long-term investments, provision on assets and on investments accounted for by equity method, costs associated with early redemption of MTNs, gain (loss) on asset dispositions. Normalized operating income also includes an adjustment for the certain non-capitalizable development costs related to energy export projects. Management believes that adjusting net income for these non-operating items is a better indicator of operating performance than net income as it is more comparable between periods.

Normalized EBITDA

($ millions)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Years Ended December 31 2015	Years Ended December 31 2014
Normalized EBITDA	**$ 173**	$ 155	**$ 582**	$ 546
Add (deduct):				
Transaction costs related to acquisitions	**(2)**	(1)	**(2)**	(1)
Loss on long-term investments	**(35)**	(2)	**(34)**	(2)
Gain on asset dispositions	**—**	27	**—**	38
Energy export development costs	**(2)**	—	**(4)**	(2)
Unrealized gain on risk management contracts	**8**	7	**9**	5
Accretion expenses	**(3)**	(3)	**(11)**	(7)
Provision on assets	**(43)**	(70)	**(54)**	(119)
Provision on investments accounted for by equity method	**(47)**	—	**(47)**	—
Costs associated with early redemption of MTNs	**—**	(14)	**—**	(17)
Foreign exchange gain	**6**	—	**6**	—
EBITDA(1)	**$ 55**	$ 99	**$ 445**	$ 441
Add (deduct):				
Depreciation and amortization	**(59)**	(47)	**(212)**	(173)
Interest expense	**(34)**	(35)	**(125)**	(111)
Income tax (expense) recovery	**(3)**	5	**(48)**	(19)
Net income (loss) after taxes (GAAP financial measure)	**$ (41)**	$ 22	**$ 60**	$ 138

(1) AltaGas revised the calculation of EBITDA to earnings before interest, taxes, depreciation and amortization effective July 1, 2015. Comparative information has been restated to reflect this change. Calculation of normalized EBITDA remains unchanged.

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 Statements 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 gain (loss) on risk management contracts, gain (loss) on long-term investments, transaction costs related to acquisitions, gain (loss) on asset dispositions, accretion expense, provision on assets and on investments accounted for by equity method, costs associated with early redemption of MTNs, and foreign exchange gain (loss). 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 as it is frequently used by analysts and investors in the evaluation of companies within the industry.

Normalized Net Income

($ millions)	Three Months Ended December 31 2015	Three Months Ended December 31 2014	Years Ended December 31 2015	Years Ended December 31 2014
Normalized net income	**$ 56**	$ 48	**$ 140**	$ 165
Add (deduct) after-tax:				
Transaction costs related to acquisitions	**(1)**	—	**(1)**	—
Unrealized gain on risk management contracts	**6**	4	**7**	3
Loss on long-term investments	**(34)**	(2)	**(33)**	(1)
Gain on asset dispositions	**—**	23	**—**	32
Provision on assets	**(33)**	(52)	**(39)**	(89)
Provision on investments accounted for by equity method	**(47)**	—	**(47)**	—
Energy export development costs	**(1)**	—	**(3)**	(1)
Costs associated with early redemption of MTNs	**—**	(11)	**—**	(13)
Statutory tax rate change	**—**	—	**(14)**	—
Net income (loss) applicable to common shares (GAAP financial measure)	**$ (54)**	$ 10	**$ 10**	$ 96

Normalized net income represents net income applicable to common shares adjusted for the after-tax impact of unrealized gain (loss) on risk management contracts, gain (loss) on long-term investments, gain (loss) on asset dispositions, provision on assets and on investments accounted for by equity method, transaction costs related to acquisitions, costs associated with early redemption of MTNs, 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

	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Normalized funds from operations	**$ 159**	$ 154	**$ 470**	$ 472
Add (deduct):				
Energy export development costs	**(1)**	—	**(1)**	—
Transaction costs related to acquisitions	**(2)**	(1)	**(2)**	(1)
Current tax expense on disposition	**(1)**	—	**(1)**	—
Funds from operations	**155**	153	**466**	471
Add (deduct):				
Net change in operating assets and liabilities	**(61)**	(53)	**39**	(11)
Asset retirement obligations settled	**(2)**	(1)	**(4)**	(2)
Cash from operations (GAAP financial measure)	**$ 92**	$ 99	**$ 501**	$ 458

Normalized funds from operations are 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 such as transaction costs related to acquisitions, energy export development costs, and current tax expense on disposition. 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.

Funds from operations are calculated from the Consolidated Statements 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.

RESULTS OF OPERATIONS BY REPORTING SEGMENT

Normalized EBITDA (1)	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Gas	**$ 44**	$ 59	**$ 172**	$ 238
Power	**53**	30	**177**	107
Utilities	**80**	74	**257**	230
Sub-total: Operating Segments	**177**	163	**606**	575
Corporate	**(4)**	(8)	**(24)**	(29)
	$ 173	$ 155	**$ 582**	$ 546

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

Normalized Operating Income (1)	Three Months Ended December 31		Years Ended December 31	
($ millions)	**2015**	2014	**2015**	2014
Gas	**$ 27**	$ 41	**$ 105**	$ 167
Power	**31**	16	**106**	65
Utilities	**60**	57	**181**	166
Sub-total: Operating Segments	**118**	114	**392**	398
Corporate	**(7)**	(9)	**(33)**	(32)
	$ 111	$ 105	**$ 359**	$ 366

(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		Years Ended December 31	
	2015	2014	**2015**	2014
Total inlet gas processed (Mmcf/d)(1)	**1,298**	1,551	**1,302**	1,512
Extraction ethane volumes (Bbls/d)(1)	**32,250**	37,811	**30,970**	34,999
Extraction NGL volumes (Bbls/d)(1)	**33,215**	38,392	**31,308**	37,777
Total extraction volumes (Bbls/d)(1) (2)	**65,465**	76,203	**62,278**	72,776
Frac spread - realized ($/Bbl)(1) (3)	**15.55**	16.29	**18.03**	18.33
Frac spread - average spot price ($/Bbl)(1) (4)	**5.06**	11.18	**5.10**	20.14

(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, divided by the respective frac exposed volumes for the period.

Total inlet gas processed for the three and twelve months ended December 31, 2015 decreased by 253 and 210 Mmcf/d, respectively, compared to the same periods in 2014. The decreases were primarily driven by lower volumes at certain extraction plants, the shut-in by the third party operator of the Empress Gas Liquids Joint Venture (EGLJV) plant, lower processed volumes at Younger and the impact of pipeline curtailments downstream of certain AltaGas processing facilities. Significantly lower commodity prices in 2015 also made extraction of certain NGL at some of the facilities uneconomical resulting in reinjections. Turnarounds at Harmattan and Younger during the second quarter of 2015 also impacted inlet volumes.

Average ethane volumes for the three and twelve months ended December 31, 2015 decreased by 5,561 and 4,029 Bbls/d, respectively, and NGL volumes decreased by 5,177 and 6,469 Bbls/d, respectively, compared to the same periods in 2014. Lower ethane volumes were due to lower produced volumes at EGLJV and EEEP facilities. NGL volumes throughout 2015 were impacted by the lower commodity price environment resulting in reinjections. Turnarounds at Harmattan and Younger during the second quarter of 2015 also impacted ethane and NGL volumes in 2015.

Three Months Ended December 31

The Gas segment reported normalized operating income of $27 million in the fourth quarter of 2015, compared to $41 million in the same quarter of 2014. The decrease in operating income reflects the significantly lower commodity price environment, lower processed volumes and the impact of pipeline curtailments downstream of certain gas processing facilities. During the fourth quarter of 2015, AltaGas recorded equity earnings of $nil from Petrogas, compared to $5 million in the same quarter of 2014. Lower earnings from Petrogas' margin-based business and the impact of reduced activities in the upstream oil and gas sector were partially offset by increased shipments from the Ferndale Terminal. Operating earnings before interest, amortization and non-cash charges of Petrogas increased in the fourth quarter of 2015 compared with the same quarter in 2014; however, this was offset by higher amortization and interest expense and certain non-cash charges that impacted net income of Petrogas.

In the fourth quarter of 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 certain gas processing assets that were held for sale; and a pre-tax provision of $7 million on the DC LNG Project related to deferred lease expense. In the fourth quarter of 2014, a $70 million pre-tax provision was taken on certain non-productive gas processing assets.

During the fourth quarter of 2015, AltaGas hedged approximately 3,000 Bbls/d of NGL at an average price of $27/Bbl. During the fourth quarter of 2014, AltaGas hedged 6,300 Bbls/d of NGL at an average price of $26/Bbl. The average indicative spot NGL frac spread for the fourth quarter of 2015 was approximately $5/Bbl compared to $11/Bbl in the same quarter of 2014. Realized frac spread of $16/Bbl in the fourth quarter of 2015 (2014 - $16/Bbl) was consistent with the same quarter in 2014 due to gains on NGL frac hedges in the quarter.

Full Year 2015

The Gas segment reported normalized operating income of $105 million for the year ended December 31, 2015, compared to $167 million in 2014. The decrease reflects the impact of weak NGL prices; lower earnings from Petrogas; completion of two major turnarounds at Younger and Harmattan during the second quarter of 2015; and lower throughput at certain gas processing facilities caused in part by third party pipeline curtailments downstream of certain AltaGas processing facilities. Third party pipeline curtailments reduced normalized operating income by $5 million. Partially offsetting these decreases were improved results from Energy Services due to unusually high costs incurred in the first quarter of 2014 to fulfill delivery commitments from operational curtailments resulting from extremely cold weather in eastern North America.

For the year ended December 31, 2015, AltaGas recorded equity earnings of $7 million from Petrogas as compared to $29 million in 2014. The decrease in Petrogas earnings was due to lower earnings from Petrogas' margin-based business, the impact of reduced activities in the upstream oil and gas sector and higher depreciation and interest related to the Ferndale Terminal and other new assets placed into service at Petrogas, partially offset by increased shipments from the Ferndale Terminal. Market conditions were particularly favourable in the first quarter of 2014, which contributed to Petrogas' strong 2014 earnings. Petrogas' earnings in 2015 were impacted by depressed commodity market conditions as well as a planned maintenance shutdown at Ferndale in the first quarter of 2015.

During the year ended December 31, 2015, AltaGas hedged approximately 3,100 Bbls/d of NGL volumes at an average price of $27/Bbl. During the year ended December 31, 2014, AltaGas hedged 5,500 Bbls/d of NGL at an average price of $26/Bbl. The average indicative spot NGL frac spread for the year ended December 31, 2015 was approximately $5/Bbl compared to approximately $20/Bbl in 2014. Realized frac spread of $18/Bbl in 2015 was consistent with 2014.

POWER

OPERATING STATISTICS

	Three Months Ended December 31		Years Ended December 31	
	2015	2014	**2015**	2014
Volume of power sold (GWh)	**1,574**	1,457	**5,708**	5,169
Average Alberta realized power price ($/MWh)	**33.83**	48.85	**41.48**	58.62
Average price realized on the sale of power ($/MWh) (1)	**61.15**	63.77	**62.40**	65.97
Alberta Power Pool average spot price ($/MWh)	**21.19**	30.47	**33.34**	49.42

(1) Price received excludes Blythe Energy Center, Ripon, Pomona, Brush II and the San Joaquin Facilities, as these facilities earn fixed capacity payments under power purchase agreements.

During the fourth quarter of 2015, volume of power sold increased by 117 GWh compared to the same quarter in 2014. Volumes sold during the fourth quarter of 2015 were comprised of 1,264 GWh of conventional power generation and 310 GWh of renewable power generation, compared to 1,249 GWh of conventional power generation and 208 GWh of renewable power generation in the same quarter of 2014.

For the year ended December 31, 2015, volume of power sold increased by 539 GWh compared to 2014. Volumes sold in 2015 were comprised of 4,408 GWh of conventional power generation and 1,300 GWh of renewable power generation, compared to 4,570 GWh conventional power generation and 599 GWh renewable power generation in 2014. The change in the generation composition was due to renewable volumes from Forrest Kerr, Volcano and McLymont, as well as the impact of the U.S. natural gas-fired assets acquired in 2015, which were offset by decreasing conventional volumes due to the disposition of peakers in Alberta in late 2014, and weak Alberta realized power prices with associated volume impacts.

Three Months Ended December 31

The Power segment reported normalized operating income of $31 million for the fourth quarter of 2015, compared to $16 million for the same quarter in 2014. Normalized operating income increased as a result of higher contributions from Forrest Kerr combined with a full quarter contribution from Volcano and the start of commercial operations at McLymont on October 28, the impact of the U.S. natural gas-fired assets acquired in 2015, and the stronger US dollar. These increases were partially offset by the impact of weaker Alberta realized power prices. The average Alberta power pool spot price dropped to a record low in the fourth quarter of 2015 to $21/MWh.

In the fourth quarter of 2015, AltaGas was 47 percent hedged in Alberta at an average price of $47/MWh. In the fourth quarter of 2014, AltaGas was 57 percent hedged at an average price of $61/MWh.

During the fourth quarter of 2015, the Power segment recorded $43 million of pre-tax provisions, comprised of $26 million for AltaGas' investment in ASTC, which holds the Sundance B PPA; as well as $17 million for certain wind development projects. No asset provisions were taken in the Power segment in the fourth quarter of 2014.

In the fourth quarter of 2015, AltaGas disposed of its effective 25 percent interest in the 7-MW run-of-river hydroelectric power generation facility on Scuzzy Creek near Boston Bar. In addition, AltaGas 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 million.

Full Year 2015

The Power segment reported normalized operating income of $106 million for the year ended December 31, 2015, compared to $65 million in 2014. Normalized operating income increased as compared to the same period in 2014 due to the contributions from Forrest Kerr and Volcano as well as the start of commercial operations at McLymont on October 28, favourable exchange rates; the impact of the six U.S. natural gas-fired assets acquired in 2015; and increased results from Blythe Energy Center due to a major planned maintenance turnaround in early 2014 and improved efficiencies at the Blythe Energy Center in 2015. This was partially offset by lower Alberta realized power prices and volumes.

For the year ended December 31, 2015, AltaGas was 50 percent hedged in Alberta at an average price of $50/MWh. AltaGas was 55 percent hedged at an average price of $64/MWh in 2014.

The Power segment recorded a total pre-tax provision of $54 million for the year ended December 31, 2015, comprised of $26 million for AltaGas' investment in ASTC and $28 million for certain wind development projects. A pre-tax provision of $11 million was recorded for the year ended December 31, 2014 related to certain small hydro power assets under development in British Columbia.

UTILITIES

OPERATING STATISTICS

	Three Months Ended December 31		Years Ended December 31	
	2015	2014	**2015**	2014
Canadian utilities				
Natural gas deliveries - end-use (PJ)[1]	**10.2**	10.6	**31.8**	32.7
Natural gas deliveries - transportation (PJ)[1]	**1.9**	1.4	**6.9**	5.6
U.S. utilities				
Natural gas deliveries - end-use (Bcf)[1]	**20.2**	23.1	**68.3**	72.3
Natural gas deliveries - transportation (Bcf)[1]	**13.5**	11.7	**47.7**	41.0
Service sites [2]	**568,751**	562,746	**568,751**	562,746
Degree day variance from normal - AUI (%) [3]	**(10.0)**	(3.6)	**(10.0)**	2.3
Degree day variance from normal - Heritage Gas (%) [3]	**(8.0)**	(8.4)	**5.6**	(0.2)
Degree day variance from normal - SEMCO Gas (%) [4]	**(20.4)**	5.1	**0.0**	16.1
Degree day variance from normal - ENSTAR (%) [4]	**(6.1)**	(10.5)	**(9.0)**	(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

Years Ended December 31	**2015**	2014
Approved ROE (%)		
Canadian utilities (average)	**9.4**	9.7
U.S. utilities (average)	**11.8**	11.2
Approved return on debt (%)		
Canadian utilities (average)	**5.1**	5.9
U.S. utilities (average)	**6.0**	5.3
Rate base *($ millions)*[1]		
Canadian utilities	**741**	692
U.S. utilities[2][3]	**851**	838

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

(2) In US dollars.

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

Three Months Ended December 31

The Utilities segment reported operating income of $60 million in the fourth quarter of 2015, compared to $57 million in the same quarter of 2014. The increase was mainly due to the impact of rate base and customer growth across all Utilities, favourable foreign exchange rates, and the approval of SEMCO Gas' MRP. The increase in operating income was partially offset by warmer weather experienced in Michigan and Alberta.

During the fourth quarter, 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. No asset provisions were taken in the Utilities segment in the fourth quarter of 2014.

Full Year 2015

The Utilities segment reported operating income of $181 million for the year ended December 31, 2015, compared to $166 million in 2014. The increase was mainly due to rate base and customer growth across all Utilities, favourable foreign exchange rates, the approval of SEMCO Gas' MRP and colder weather experienced in Nova Scotia. The increase in operating income was partially offset by warmer weather experienced in Michigan and Alberta, and higher operating costs due to increased pension, retiree medical, and severance costs.

On June 3, 2015, SEMCO Gas' MRP case was approved by the MPSC. This program was for the recovery of capital expenses projected from 2016 to 2020 combined with a reconciliation of the current program that expires in December 2015. The new rates took effect immediately, resulting in approximately US$4 million of additional operating income for the year ended December 31, 2015.

CORPORATE

Three Months Ended December 31

In the Corporate segment, normalized operating loss for the fourth quarter of 2015 was $7 million, compared to $9 million in the same quarter of 2014. The decrease was mainly due to cost saving initiatives implemented in 2015 partially offset by higher depreciation and amortization expense on major IT projects placed into service in 2015.

During the fourth quarter of 2015, a pre-tax charge of $35 million was recorded related to AltaGas' investment in common shares of Painted Pony.

Full Year 2015

Normalized operating loss for the year ended December 31, 2015 was $33 million, compared to $32 million in 2014. The increase in normalized operating loss was due to higher depreciation and amortization expense on major IT projects placed into service in 2015, partially offset by cost saving initiatives implemented in 2015.

INVESTED CAPITAL

During the fourth quarter of 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $1.1 billion, compared to $194 million in the same quarter of 2014. The net invested capital was $1.1 billion for the fourth quarter of 2015, compared to $157 million in the same quarter of 2014. The increase from 2014 was mainly as a result of the acquisition of the San Joaquin Facilities, which closed on November 30, 2015.

The invested capital in the fourth quarter of 2015 included maintenance capital of $4 million (2014 - $6 million) in the Gas segment and $2 million (2014 - $nil) in the Power segment.

	Three Months Ended December 31, 2015				
($ millions)	**Gas**	**Power**	**Utilities**	**Corporate**	**Total**
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**

($ millions)		Gas		Power		Utilities		Corporate		Three Months Ended December 31, 2014 Total
Invested capital:										
Property, plant and equipment	$	44	$	58	$	76	$	3	$	181
Intangible assets		—		—		2		7		9
Long-term investments		1		—		—		3		4
		45		58		78		13		194
Disposals:										
Property, plant and equipment		—		(37)		—		—		(37)
Net Invested capital	$	45	$	21	$	78	$	13	$	157

During the year ended December 31, 2015, AltaGas increased property, plant and equipment, intangible assets and long-term investments by $1.6 billion, compared to $654 million in 2014. The net invested capital was approximately $1.6 billion for the year ended December 31, 2015, compared to $590 million in 2014.

During 2015, the Power segment paid $11 million (2014 - $5 million) to BC Hydro in support of the construction and operation of the Northwest Transmission Line.

The invested capital for year ended December 31, 2015 included maintenance capital of $23 million (2014 - $12 million) in the Gas segment and $4 million (2014 - $nil) in the Power segment. Gas segment maintenance capital included $8 million related to the Harmattan turnaround during the second quarter of 2015 (2014 - $nil).

($ millions)		**Gas**		**Power**		**Utilities**		**Corporate**		**Year Ended December 31, 2015 Total**
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**

($ millions)		Gas		Power		Utilities		Corporate		Year Ended December 31, 2014 Total
Invested capital:										
Property, plant and equipment	$	91	$	285	$	184	$	7	$	567
Intangible assets		—		5		2		20		27
Long-term investments		7		—		—		53		60
		98		290		186		80		654
Disposals:										
Property, plant and equipment		(27)		(37)		—		—		(64)
Net Invested capital	$	71	$	253	$	186	$	80	$	590

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, interest rates, and foreign exchange rates. As at December 31, 2015 and 2014, the fair values of the Corporation's derivatives were as follows:

As at December 31 *($ millions)*		**2015**		2014
Natural gas	**$**	**3.1**	$	(3.9)
Storage optimization		**2.5**		0.9
NGL frac spread		**—**		20.9
Power		**19.5**		15.9
Heat rate		**0.1**		0.4
Foreign exchange		**(0.5)**		(0.5)
	$	**24.7**	$	33.7

Commodity Price Contracts

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. The calculation of fair value of foreign exchange derivatives used quoted market rates.

AltaGas does not speculate on commodity prices and therefore does not engage in commodity transactions that create incremental exposure or are based solely on expectations of future energy market price movements. Commodity transactions are used to lock in margins, optimize underlying physical assets or reduce exposure to energy price movements. AltaGas' risk management group reviews commodity and credit risk on a daily basis, and has created and adheres to a conservative risk policy and hedging program.

Power hedges:

AltaGas executes fixed for floating power price swaps to manage its Alberta power asset portfolio. A fixed for floating price swap is an agreement between two counterparties to exchange a fixed price for a floating price. The Power segment results are affected by the price of electricity in Alberta. AltaGas employs derivative commodity instruments for the purpose of managing AltaGas' exposure to power price volatility. The Alberta Power Pool settles power prices on an hourly basis and prices ranged from $0/MWh to $998/MWh in 2015 and $8/MWh to $1,000/MWh in 2014. The average Alberta spot price was approximately $33/MWh in 2015 (2014 - $49/MWh). AltaGas moderated the impact of this volatility on its business through the use of financial hedges on a portion of its power portfolio. The average realized Alberta power price was approximately $41/MWh in 2015 (2014 - $59/MWh).

NGL frac spread hedges:

The Corporation 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. During 2015, the Corporation hedged approximately 3,100 Bbls/d of NGL at an average price of approximately $27/Bbl. The average indicative spot NGL frac spread for 2015 was an estimated $5/Bbl (2014 – $20/Bbl). The average NGL frac spread realized by AltaGas in 2015 was approximately $18/Bbl (2014 - $18/Bbl). Given the weak commodity prices, AltaGas does not expect to enter into frac hedges for 2016 at this time.

Foreign Exchange

Foreign exchange exposure created by transacting commercial arrangements in foreign currency is managed through the use of foreign exchange forward contracts, whereby a fixed rate is locked in against a floating rate; and option agreements, whereby an option to transact foreign currency at a future date is purchased or sold. Foreign exchange gains and losses on long-term debt denominated in US dollars are unrealized and can only be realized when the long-term debt matures or is settled.

As at December 31, 2015, management designated US$724 million of outstanding debt to hedge against the currency translation effect of its foreign investments (December 31, 2014 - US$375 million). US 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 US dollar denominated long-term debt and foreign net investment. For the year ended December 31, 2015, AltaGas incurred after-tax unrealized loss of $98.7 million arising from the translation of debt in other comprehensive income (December 31, 2014 - after-tax unrealized loss of $35.0 million).

The Effects of Derivative Instruments on the Consolidated Statements of Income

The following table presents the unrealized gains or losses on derivative instruments as recorded in the Corporation's consolidated statements of income:

Years Ended December 31 *($ millions)*		**2015**		2014
Natural gas	**$**	**7.2**	$	(7.9)
Storage optimization		**(0.4)**		2.1
NGL frac spread		**(3.2)**		3.2
Power		**6.3**		7.5
Heat rate		**(0.3)**		0.1
Foreign exchange		**(0.1)**		(0.3)
Embedded derivative		**(0.1)**		—
	$	**9.4**	$	4.7

Please refer to Note 19 of the 2015 Annual Consolidated Financial Statements for further details regarding AltaGas' risk management activities, including a sensitivity analysis on the potential impact on pre-tax income due to changes in the fair value of risk management contracts in place as at December 31, 2015.

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 cost 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; deliveries of certain hedge contracts are suspended if there is an outage at Sundance B
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 US 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 monitoring 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 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 include specified target availability levels • 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 • Own and operate gas-fired peaking capacity to backstop the Sundance B PPA and sell energy and ancillary services • Increase base-load natural gas-fired generating capacity where cost effective to do so • 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

Risks	Strategies and Organizational Capability to Mitigate Risks
	• Closely monitor exposures and impact of price shocks on liquidity • Build a diverse customer and supplier base • 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
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

LIQUIDITY

	Years Ended December 31	
($ millions)	**2015**	2014
Cash from operations	**$ 501**	$ 458
Investing activities	**(1,516)**	(591)
Financing activities	**930**	456
Effect of exchange rate	**7**	4
Increase (decrease) in cash and cash equivalents	**$ (78)**	$ 327

Cash from Operations

Cash from operations increased by $43 million for the year ended December 31, 2015 compared to 2014 primarily due to higher cash contributions from new assets placed into service, the favourable US dollar exchange rate, and the U.S. natural gas-fired power assets acquired in 2015, partially offset by lower commodity prices and volumes, and lower distributions from the Corporation's equity investments. AltaGas received $11 million in dividends from Petrogas in 2015, compared with $54 million in dividends in 2014. The increase in cash from operations was also impacted by the favourable variance in net change in operating assets and liabilities. The net change in operating assets and liabilities was a net cash inflow of $39 million for the year ended December 31, 2015 compared to net cash outflow of $11 million in 2014. The higher net cash inflow is due to changes in accounts receivable, inventory, and regulatory assets, largely as a result of changes in gas commodity costs, partially offset by an increase in payments for other assets, and higher accounts receivable relating to the Northwest Hydro Facilities.

Working Capital *($ millions except current ratio)*	**December 31, 2015**	December 31, 2014
Current assets	**$ 1,038**	$ 1,058
Current liabilities	**948**	763
Working capital	**$ 90**	$ 295
Working capital ratio	**1.09**	1.39

The decrease in working capital ratio was primarily due to the decrease in cash and cash equivalents and accounts receivable, the maturity of a $50 million short-term investment during 2015, higher accounts payable and an increase in debt maturing within one-year of December 31, 2015. This was partially offset by the reclassification of $90 million of non-current net assets to current, due to the planned sale of certain non-core gas processing assets.

Investing Activities

Cash used in investing activities for the year ended December 31, 2015 was $1.5 billion, compared to $591 million in 2014. 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. Investing activities in 2014 primarily comprised of $520 million for property, plant, and equipment, $29 million for intangible assets, $50 million for acquisition of a short-term investment, and $53 million for acquisition of long-term investments, partially offset by proceeds of $65 million received on disposition of assets.

Financing Activities

Cash from financing activities in 2015 was $930 million, compared to $456 million in 2014. Financing activities in 2015 were primarily comprised of net proceeds from the issuance of long-term debt of $1.1 billion, common shares of $403 million, and preferred shares of $196 million and the net issuance of $47 million of short-term debt, partially offset by repayment of $476 million of long-term debt. Financing activities in 2014 were primarily comprised of net proceeds from issuance of long-term debt of $1.3 billion, net proceeds from issuance of common shares of $535 million, and issuance of preferred shares of $194 million, partially offset by repayments of long-term and short-term debt of $1.3 billion and $18 million, respectively. Total dividends paid to common and preferred shareholders in 2015 were $296 million, compared to $245 million in the same period in 2014. The increase was due to more common shares outstanding and dividend increases declared in 2015.

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 and short-term investments.

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, 2015**	December 31, 2014
Short-term debt	**$ 131**	$ 72
Current portion of long-term debt	**288**	214
Long-term debt[(1)]	**3,732**	3,032
Total debt	**4,151**	3,318
Less: cash and cash equivalents	**(293)**	(371)
Less: short-term investments	**—**	(50)
Net debt	**$ 3,858**	$ 2,897
Shareholders' equity	**4,168**	3,541
Non-controlling interests	**35**	33
Total capitalization	**$ 8,061**	$ 6,471
Debt-to-total capitalization (%)	**48**	45

(1) Net of debt issuance costs of $15 million as at December 31, 2015 (December 31, 2014 - $18 million).

As at December 31, 2015, AltaGas’ total debt primarily consisted of outstanding MTNs of $2.8 billion (December 31, 2014 - $2.8 billion), PNG debenture notes of $47 million (December 31, 2014 - $57 million), SEMCO long-term debt of $522 million (December 31, 2014 - $443 million) and $811 million drawn under the bank credit facilities (December 31, 2014 - $46 million). In addition, AltaGas had $147 million of letters of credit (December 31, 2014 - $136 million) outstanding.

As at December 31, 2015, AltaGas' total market capitalization was approximately $5.3 billion based on approximately 146 million common shares; approximately 6 million series A Preferred Shares; approximately 2 million series B Preferred Shares; 8 million series C US$ Preferred Shares; 8 million series E Preferred Shares; 8 million series G Preferred Shares; and 8 million series I Preferred Shares outstanding, and a closing trading price on December 31, 2015 of $30.87 per common share; $16.17 per series A Preferred Share; $14.05 per series B Preferred Share; $20.27 per series C US$ Preferred Share; $21.78 per series E Preferred Share; $20.99 per series G Preferred Share; and $25.05 per series I Preferred Share, respectively.

AltaGas' earnings interest coverage for the rolling 12 months ended December 31, 2015 was 1.5 times.

Credit Facilities

($ millions)	Borrowing capacity	**Drawn at December 31, 2015**	Drawn at December 31, 2014
Demand operating facilities	$ 70	**$ 4**	$ 4
Extendible revolving letter of credit facility	150	**56**	113
Letter of credit demand facility	150	**80**	—
PNG operating facility	25	**10**	14
Bilateral letter of credit facility [(1)]	—	**—**	13
AltaGas Ltd. revolving credit facility [(2)]	1,400	**690**	—
SEMCO Energy US$ unsecured credit facility [(2) (3)]	150	**118**	38
	$ 1,945	**$ 958**	$ 182

(1) Effective September 2015, the bilateral letter of credit facility was closed.

(2) Amount drawn at December 31, 2015 converted at the month-end rate of 1 US dollar = 1.3840 Canadian dollar (December 31, 2014 - 1 US dollar = 1.1601 Canadian dollar).

(3) 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, 2015**
Bank debt-to-capitalization[(1)]	not greater than 65 percent	46.2%
Bank EBITDA-to-interest expense [(1) (2)]	not less than 2.5x	4.10
Bank debt-to-capitalization (SEMCO)[(3)]	not greater than 60 percent	46.7%
Bank EBITDA-to-interest expense (SEMCO)[(3)]	not less than 2.25x	6.61

(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, 2015, $4.5 billion remains available under the base shelf prospectus.

CONTRACTUAL OBLIGATIONS

December 31, 2015 Payments Due by Period

($ millions)	Total	Less than 1 year	1 - 3 years	4 - 5 years	After 5 years
Short-term debt [(1)]	$ 130.7	$ 130.7	$ —	$ —	$ —
Long-term debt [(1)]	4,035.1	287.6	578.1	1,520.3	1,649.1
Operating leases	91.7	27.6	39.6	11.6	12.9
Purchase obligations	2,395.0	382.8	677.5	569.1	765.6
Capital project commitments	64.9	64.9	—	—	—
Pension plan and retiree benefits	20.1	20.1	—	—	—
Long-term liabilities	162.2	11.0	20.7	20.0	110.5
Total contractual obligations [(2)]	$ 6,899.7	$ 924.7	$ 1,315.9	$ 2,121.0	$ 2,538.1

(1) Excludes interest payments.

(2) US dollar commitments have been converted to Canadian dollar using the December 31, 2015 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 2015 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 December 16, 2015, Standard & Poor's (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 Limited (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.

On November 14, 2014, DBRS Limited (DBRS) reaffirmed the BBB and Pfd-3 ratings for AltaGas.

On July 3, 2014, DBRS commenced rating of the Series G Preferred Shares with a rating of Pfd-3.

On July 2, 2014, Standard & Poor's (S&P) assigned a rating of P-3 (High) to the Series G Preferred Shares.

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. DBRS rates AltaGas BBB with a stable trend.

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. S&P rates AltaGas BBB with a negative outlook.

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

On September 30, 2015, AltaGas closed a public offering of 8,760,000 Common Shares at a price of $34.25 per Common Share for aggregate gross proceeds of approximately $300 million.

On September 30, 2015, 2,488,780 of the outstanding 8,000,000 Cumulative Redeemable Five Year Fixed Rate Reset Preferred Shares, Series A were converted into Cumulative Floating Rate Preferred Shares, Series B.

On November 23, 2015, AltaGas closed a public offering of 8,000,000 Cumulative Redeemable 5-Year Minimum Rate Reset Preferred Shares, Series I, at a price of $25.00 per Series I, Preferred Share for aggregate gross proceeds of $200 million.

	As at February 17, 2016
Issued and outstanding	
Common shares	146,920,619
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
Issued	
Share options	4,559,761
Share options exercisable	2,993,946

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 as impacted by the consolidated net income, maintenance and growth capital expenditures, and debt repayment requirements of AltaGas.

On April 30, 2015, the Board of Directors approved an increase in the monthly dividend to $0.16 per common share from $0.1475 per common share effective with the May dividend.

On September 18, 2015, the Board of Directors approved an increase in the monthly dividend to $0.165 per common share from $0.16 per common share effective with the October dividend.

On September 30, 2015, the Series A preferred shares annual fixed dividend rate was reset to 3.38 percent. The dividend rate will reset on September 30, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield plus 2.66 percent.

The Series B preferred shares will pay a floating quarterly dividend for the five-year period beginning on September 30, 2015 at a rate equal to the sum of the then 90-day Government of Canada Treasury Bill plus 2.66 percent, and will reset every quarter. The first quarterly floating rate period (being the period from September 30, 2015 to, but excluding, December 31, 2015) is 3.04 percent. Commencing December 31, 2015, the floating quarterly dividend rate is 3.10 percent for the period from December 31, 2015 to, but excluding, March 31, 2016.

Holders of the Series I preferred shares will receive the first quarterly dividend payment on March 31, 2016 of $0.46387 per Series I preferred share. The dividend rate will reset on December 31, 2020 and every five years thereafter at a rate equal to the sum of 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.

The following table summarizes AltaGas' dividend declaration history:

Dividends
Years ended December 31

($ per common share)		**2015**		2014
First quarter	**$**	**0.44250**	$	0.38250
Second quarter		**0.46750**		0.42250
Third quarter		**0.48000**		0.44250
Fourth quarter		**0.49500**		0.44250
Total	**$**	**1.88500**	$	1.69000

Series A Preferred Share Dividends
Years ended December 31

($ per preferred share)		**2015**		2014
First quarter	**$**	**0.31250**	$	0.31250
Second quarter		**0.31250**		0.31250
Third quarter		**0.31250**		0.31250
Fourth quarter		**0.21125**		0.31250
Total	**$**	**1.14875**	$	1.25000

Series B Preferred Share Dividends
Years ended December 31

($ per preferred share)		**2015**		2014
Fourth quarter	**$**	**0.19156**	$	—
Total	**$**	**0.19156**	$	—

Series C Preferred Share Dividends
Years ended December 31

(US$ per preferred share)		**2015**		2014
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

Years ended December 31

($ per preferred share)		2015		2014
First quarter	**$**	**0.31250**	$	0.36990
Second quarter		**0.31250**		0.31250
Third quarter		**0.31250**		0.31250
Fourth quarter		**0.31250**		0.31250
Total	**$**	**1.25000**	$	1.30740

Series G Preferred Share Dividends

Years ended December 31

($ per preferred share)		2015		2014
First quarter	**$**	**0.29690**	$	—
Second quarter		**0.29690**		—
Third quarter		**0.29690**		0.28960
Fourth quarter		**0.29690**		0.29690
Total	**$**	**1.18760**	$	0.58650

CRITICAL ACCOUNTING ESTIMATES

Since a determination of the value of many assets, liabilities, revenues, and expenses is dependent upon future events, the preparation of the 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 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, interest rate 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, currency exchange and interest rate yield curves. 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.

With respect to impairment assessment, management has made fair value determinations related to goodwill, estimating future cash flows as well as appropriate discount rates. The estimates have been applied consistently with prior periods.

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. 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 2015 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 25 to the 2015 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 July 1, 2015, AltaGas early adopted Financial Accounting Standards Board (FASB) Accounting Standards Update (ASU) 2015-03 “Simplifying the Presentation of Debt Issuance Costs”. Under the ASU, debt issuance costs are recorded as a direct deduction from the related debt liability rather than as an asset. Upon adoption, AltaGas reclassified debt issuance costs of $16 million and $18 million for the periods ended June 30, 2015 and December 31, 2014, respectively, from “Long-term investments and other assets” to “Long-term debt”. Debt issuance costs related to line-of-credit arrangements were not reclassified pursuant to guidance from ASU 2015-15 “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements”.

Effective August 2015, AltaGas prospectively adopted FASB issued ASU No. 2015-13 “Derivatives and Hedging - Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets”, which allows certain forward contracts for physical delivery of electricity in nodal energy markets to qualify for the normal purchases and normal sales scope exception, as long as the physical delivery criterion and other criteria for the normal purchases and normal sales scope exception are met. The ASU applies to forward contracts in which one of the counterparties incurs location marginal pricing charges (or credits) payable to (or receivable from) an independent system operator. The adoption of this ASU did not have an impact on AltaGas’ consolidated financial statements.

Effective October 1, 2015, AltaGas early adopted FASB issued ASU No. 2015-17 “Balance Sheet Classification of Deferred Taxes” which requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as non-current on the balance sheet. Upon adoption, AltaGas reclassified current deferred income tax assets of $2 million and $nil, for the periods ended September 30, 2015 and December 31, 2014, respectively, to non-current deferred income tax asset. Current deferred income tax liabilities of $nil and $2 million for the periods ended September 30, 2015 and December 31, 2014, respectively, were reclassified to non-current deferred income tax liabilities.

FUTURE CHANGES IN ACCOUNTING PRINCIPLES

In May 2014, FASB issued ASU 2014-09, "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. On July 9, 2015, FASB confirmed a one-year deferral of the new revenue standard. The new 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. Early adoption prior to that date would not be permitted. AltaGas commenced a process for the adoption of the ASU and the impact on AltaGas' consolidated financial statements is under assessment.

In February 2015, FASB issued 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 amendments in this ASU are effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2015. Early adoption is permitted. The adoption of this ASU is not expected to have a material impact on AltaGas’ consolidated financial statements.

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. AltaGas is currently evaluating the impact of adopting this ASU on its consolidated financial statements.

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 the third party owners of the transportation facility.

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 have 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, 2015 and concluded that as at December 31, 2015, AltaGas' DCP and ICFR were effective.

On January 1, 2015, AltaGas launched a new enterprise resource planning system, JD Edwards EnterpriseOne. The changes to the internal controls over financial reporting are included in the assessment to ensure that DCP and ICFR are designed 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, reliably reported on a timely basis, and financial statements are in accordance with U.S. GAAP.

Pursuant to Section 3.3(1)(b) of National Instrument 52-109, the Chief Executive Officer and Chief Financial Officer of AltaGas with the assistance of AltaGas employees, have limited the scope of AltaGas' design of DCP and ICFR to exclude the controls, policies and procedures relating to the San Joaquin Facilities acquired on November 30, 2015. Summary financial information related to the San Joaquin Facilities, which have been included in the 2015 Annual Consolidated Financial Statements for as at, and for the year ended December 31, 2015 is as follows:

($ millions)		
Revenues	$	11
Operating income	$	6
Current assets	$	44
Non-current assets	$	979
Current liabilities	$	14
Non-current liabilities	$	91

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)	**Q4-15**	Q3-15	Q2-15	Q1-15	Q4-14	Q3-14	Q2-14	Q1-14
Total revenue	**580**	452	416	744	667	444	471	824
Net revenue(2)	**216**	268	204	307	285	217	220	297
Normalized operating income(2)	**111**	69	54	125	105	59	64	137
Net income (loss) applicable to common shares	**(54)**	20	(22)	66	10	17	29	40
($ per share)	**Q4-15**	Q3-15	Q2-15	Q1-15	Q4-14	Q3-14	Q2-14	Q1-14
Net income (loss) per common share								
Basic	**(0.37)**	0.15	(0.16)	0.49	0.08	0.13	0.23	0.33
Diluted	**(0.37)**	0.14	(0.16)	0.49	0.08	0.13	0.23	0.32
Dividends declared	**0.50**	0.48	0.47	0.44	0.44	0.44	0.42	0.38

(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, the US/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 quarter of any given year as the majority of natural gas demand occurs during the winter heating season, which typically extends from November to March. Other significant items that impacted quarter-over-quarter revenue during the periods noted include:

- The commissioning of the hydroelectric power generating facilities, Forrest Kerr and Volcano during the latter part of 2014 and McLymont in the fourth quarter of 2015. These run-of-river hydroelectric facilities are impacted by seasonal precipitation and snowpack melt, which create periods of high flow during the spring and summer months;

- The acquisition of U.S. natural gas-fired power assets in the first quarter of 2015;
- The Harmattan and Younger turnarounds in the second quarter of 2015;
- The weak NGL commodity prices during the latter part of 2014 and throughout 2015;
- The San Joaquin Facilities acquired on November 30, 2015; and
- The stronger US dollar on translated results of the U.S. assets throughout 2015.

Net income (loss) applicable to common shares are also affected by non-cash items such as deferred income tax, depreciation and amortization expense, accretion expense, provision on assets and gain or loss on asset dispositions. In addition, net income (loss) applicable to common shares is also impacted by preferred shares dividend. 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 were impacted by:

- An after-tax provision of $37 million for EDS and JFP transmission pipeline assets and certain hydro power development assets recorded in the first quarter of 2014;
- Higher interest and depreciation and amortization expense since the third quarter of 2014 due to new assets placed into service and interest no longer eligible for capitalization;
- An after-tax provision of $52 million for certain gas processing assets in the fourth quarter of 2014;
- 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; and
- 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 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 and assets in the Ikhil Joint Venture.

SELECTED ANNUAL FINANCIAL INFORMATION

($ millions, except where noted)	**2015**	2014	2013
Revenue	**2,193**	2,406	2,043
Net income applicable to common shares	**10**	96	182
Basic ($ per share)	**0.07**	0.75	1.56
Diluted ($ per share)	**0.07**	0.74	1.52
Total assets	**10,100**	8,396	7,284
Total long-term financial liabilities	**3,899**	3,202	2,960
Weighted average number of common shares outstanding (millions)	**138**	127	116
Dividends declared per common share ($ per share)	**1.88500**	1.69000	1.49250
Preferred share dividends declared ($ per share)			
Series A	**1.14875**	1.25000	1.25000
Series B	**0.19156**	—	—
Series C	**1.10000**	1.10000	1.10000
Series E	**1.25000**	1.30740	—
Series G	**1.18760**	0.58650	—

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
PJ	petajoule
MMBTU	million British thermal unit

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 renewable energy sources. For more information visit: www.altagas.ca.

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