# MANAGEMENT'S DISCUSSION AND ANALYSIS

For the year ended December 31, 2015

## FINANCIAL AND OPERATING HIGHLIGHTS

| | Year ended December 31 | | |
|---|---|---|---|
| ($ Millions, except where noted) | **2015** | 2014 | 2013 |
| **Operating Highlights (100%)** | | | |
| Pipeline | | | |
| Alliance – billion cubic feet per day | **1.488** | 1.556 | 1.565 |
| Ruby – billion cubic feet per day | **0.805** | 1.020 | – |
| AEGS – thousand barrels per day(1) | **285.6** | 289.1 | 293.0 |
| Midstream | | | |
| Hythe/Steeprock – million cubic feet per day(2) | **392.6** | 399.9 | 412.9 |
| Dawson – million cubic feet per day(2) | **634.1** | – | – |
| Aux Sable – thousand barrels per day | **66.5** | 70.2 | 70.4 |
| Power – gigawatt hours (net) | **603.0** | 638.0 | 561.5 |
| **Financial Results** | | | |
| Equity income and dividend income | **193** | 162 | 163 |
| Operating revenues | **187** | 302 | 292 |
| Adjusted net income attributable to Common Shares(3)(4) | **66** | 25 | 41 |
| Per Common Share ($) – basic and diluted | **0.23** | 0.11 | 0.21 |
| Net income attributable to Common Shares | **60** | 52 | 53 |
| Per Common Share ($) – basic and diluted | **0.21** | 0.24 | 0.27 |
| Cash from operating activities | **287** | 215 | 217 |
| Distributable cash(3)(5) | **310** | 253 | 229 |
| Per Common Share ($) – basic and diluted | **1.06** | 1.12 | 1.15 |
| Dividends paid/payable(6) | **291** | 227 | 200 |
| Per Common Share ($) | **1.00** | 1.00 | 1.00 |
| Capital expenditures(7) | **58** | 148 | 46 |
| **Financial Position** | | | |
| Cash and short-term investments | **58** | 51 | 25 |
| Total assets | **4,571** | 4,737 | 2,973 |
| Senior debt | **1,100** | 1,811 | 1,188 |
| Subordinated convertible debentures | **–** | – | 86 |
| Shareholders' equity | **3,087** | 2,532 | 1,306 |
| **Common Shares** | | | |
| Outstanding – as at year end(8) | **298,979,989** | 285,029,036 | 201,476,244 |
| Average daily volume | **854,092** | 701,764 | 302,801 |
| Price per Common Share – close ($) | **8.86** | 18.36 | 14.27 |

(1) Average daily volume for AEGS is based on toll volumes.

(2) Average daily volume for Hythe/Steeprock and Dawson is based on fee volumes and throughput volumes, respectively.

(3) This item is not a standard measure under US GAAP and may not be comparable to similar measures presented by other entities. See section entitled *"Non-GAAP Financial Measures"* in this MD&A.

(4) We have provided a reconciliation of adjusted net income attributable to Common Shares to net income attributable to Common Shares in the *"Non-GAAP Financial Measures"* section of this MD&A.

(5) We have provided a reconciliation of distributable cash to cash from operating activities in the *"Non-GAAP Financial Measures"* section of this MD&A.

(6) Includes $182 million of dividends satisfied through the issuance of Common Shares under our Premium Dividend™ and Dividend Reinvestment Plan (trademark of Canaccord Genuity Corp.) for the year ended December 31, 2015 (2014 – $81 million).

(7) Capital expenditures for wholly-owned and majority-controlled businesses, as presented on the consolidated statement of cash flows.

(8) As at the close of markets on March 4, 2016 we had 303,096,627 Common Shares outstanding.

This MD&A, dated March 9, 2016, provides a review of the significant events and transactions that affected our performance during the year ended December 31, 2015 relative to December 31, 2014. It should be read in conjunction with our consolidated financial statements and notes as at and for the year ended December 31, 2015, prepared in accordance with accounting principles generally accepted in the United States ("US GAAP").

## OVERALL FINANCIAL PERFORMANCE

Against the backdrop of a very challenging environment, Veresen delivered solid financial results in 2015. Our results highlight the sound underpinning of our business model – a diversified portfolio of well-located, high quality infrastructure assets supported by long-term fee-based contracts with a strong counterparty credit profile. Although Aux Sable, our one commodity-exposed business, continues to operate in a weak NGL market, the balance of our business is healthy, providing a stable foundation that will allow us to maintain performance through this cycle.

### Adjusted Net Income attributable to Common Shares

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ Millions, except per Common Share amounts) | **2015** | 2014 | **2015** | 2014[2] |
| Adjusted net income before tax[1] | | | | |
| Pipeline | **67** | 44 | **256** | 137 |
| Midstream | **(1)** | 21 | **6** | 81 |
| Power | **8** | 1 | **11** | 6 |
| Veresen – Corporate and Project Development | **(44)** | (43) | **(157)** | (161) |
| Tax expense | **(8)** | (10) | **(26)** | (22) |
| **Adjusted net income** | **22** | 13 | **90** | 41 |
| **Preferred Share dividends** | **(7)** | (4) | **(24)** | (16) |
| **Adjusted net income attributable to Common Shares** | **15** | 9 | **66** | 25 |
| **Per Common Share ($)** | **0.05** | 0.03 | **0.23** | 0.11 |

(1) See the reconciliation of adjusted net income attributable to Common Shares to net income attributed to Common Shares in the *"Non-GAAP Financial Measures"* section of this MD&A.

(2) Certain comparative figures for the year ended December 31, 2014 have been adjusted. Refer to the reconciliation noted above in the *"Non-GAAP Financial Measures"* section of this MD&A.

Adjusted net income attributable to Common Shares represents net income adjusted for specific items that are significant, but are not reflective of our underlying operations. We have presented adjusted net income attributable to Common Shares in order to enhance the comparability of our earnings. See the *Non-GAAP Financial Measures* section of this MD&A for the full definition of this term and the reconciliation to net income attributable to Common Shares.

For the year ended December 31, 2015, we generated adjusted net income attributable to Common Shares of $66 million or $0.23 per Common Share compared to an adjusted net income of $25 million or $0.11 per Common Share in 2014.

Our adjusted earnings reflect the benefits of diversification achieved through our strategic initiatives with a full year of earnings from our interest in the Ruby Pipeline and the successful re-contracting of the Alliance Pipeline under a new business model effective December 2015. The advancement of our Jordan Cove liquefied natural gas ("LNG") development project continues to be a key component of our strategy. Funding requirements during the development phase are expensed.

Adjusted earnings from our Pipeline business increased year over year, resulting from our full-year ownership in the Ruby Pipeline, acquired November 6, 2014. We earned $116 million from our interest in Ruby in 2015 compared to $16 million in 2014. Alliance also contributed to higher adjusted earnings.

Power earnings were also higher this year with the incremental contributions from our new run-of-river hydro and wind facilities.

The increases in Pipeline and Power earnings were partially offset by lower Midstream adjusted earnings, driven by continuing weak NGL margins as a result of low propane prices, and reduced ownership in the Hythe/Steeprock business resulting from the sale of these facilities to Veresen Midstream in the first quarter of 2015.

Corporate costs in 2015 were relatively consistent with the prior year as higher Jordan Cove project spending was offset by lower general and administrative costs due to the revaluation of our long-term incentive plans.

Fourth quarter adjusted earnings reflect the same underlying factors as discussed above for the full year.

### Net Income attributable to Common Shares

| ($ Millions, except per Common Share amounts) | Three months ended December 31 2015 | 2014 | Year ended December 31 2015 | 2014 |
|---|---|---|---|---|
| **Net income before tax** | | | | |
| Pipeline | **67** | 44 | **256** | 137 |
| Midstream | **(18)** | 21 | **(33)** | 81 |
| Power | **13** | (3) | **10** | (2) |
| Veresen – Corporate and Project Development | **(44)** | (9) | **(157)** | (122) |
| Gain on sale of assets (impairment) | **–** | (5) | **37** | 9 |
| Tax expense | **3** | (13) | **(19)** | (25) |
| **Net income from continuing operations** | **21** | 35 | **94** | 78 |
| Net loss from discontinued operations | **–** | (10) | **–** | (10) |
| **Net income, before extraordinary loss** | **21** | 25 | **94** | 68 |
| **Extraordinary loss, net of tax** | **–** | – | **(10)** | – |
| **Net income** | **21** | 25 | **84** | 68 |
| **Preferred Share dividends** | **(7)** | (4) | **(24)** | (16) |
| **Net income attributable to Common Shares** | **14** | 21 | **60** | 52 |
| **Per Common Share ($)** | **0.05** | 0.08 | **0.21** | 0.24 |

For the year ended December 31, 2015, we generated net income attributable to Common Shares of $60 million or $0.21 per Common Share. In 2014, we generated net income of $52 million or $0.24 per Common Share.

In addition to factors impacting adjusted net income, as previously discussed, the following items are reflected in net income.

Midstream results include a non-cash provision of $32 million related to Aux Sable and a $37 million pre-tax gain relating to the sale of our Hythe/Steeprock assets to Veresen Midstream.

Power results include the impact of the revaluation of interest rate hedges resulting in an aggregate pre-tax $1 million loss in 2015 compared to a pre-tax $12 million loss last year.

Corporate results in 2014 included a $39 million pre-tax gain associated with forward foreign exchange contracts we entered into to manage the foreign exchange exposure relating to the acquisition of our 50% convertible interest in Ruby that closed in the fourth quarter of 2014.

During 2014 we generated a pre-tax gain of $14 million from the sale of certain power development projects and recorded a $5 million impairment loss on land we hold in Ontario.

During the second quarter of 2015 we recognized an extraordinary after-tax loss of $10 million representing the one-time net effect of Alliance's de-recognition of certain regulatory assets and liabilities.

Fourth quarter earnings were impacted by a provision of $16 million related to Aux Sable and the revaluation of interest rate hedges within our Power segment resulting in an aggregate pre-tax $5 million gain in 2015 compared to a $4 million loss in 2014. During the fourth quarter of 2014, we recognized a $34 million pre-tax gain associated with the foreign exchange contracts relating to our acquisition of Ruby, a $12 million impairment of the three U.S. gas-fired assets sold, and a $5 million land impairment.

## Distributable Cash

| ($ Millions, except per Common Share amounts) | Three months ended December 31 2015 | 2014 | Year ended December 31 2015 | 2014 |
|---|---|---|---|---|
| Pipeline | **83** | 57 | **302** | 180 |
| Midstream | **19** | 34 | **76** | 131 |
| Power | **14** | 8 | **43** | 47 |
| Veresen – Corporate | **(9)** | (18) | **(53)** | (66) |
| Current tax | **(7)** | (9) | **(34)** | (23) |
| Preferred Share dividends | **(7)** | (4) | **(24)** | (16) |
| **Distributable Cash**[1] | **93** | 68 | **310** | 253 |
| **Per Common Share ($)** | **0.31** | 0.26 | **1.06** | 1.12 |

(1) See the reconciliation of distributable cash to cash from operating activities in the *"Non-GAAP Financial Measures"* section of this MD&A.

For the year ended December 31, 2015, we generated distributable cash of $310 million or $1.06 per Common Share, compared to $253 million or $1.12 per Common Share in 2014.

Increased cash flows generated by our Pipeline businesses and reduced Corporate costs were partially offset by reduced cash flows from our Aux Sable midstream business, and higher cash taxes and preferred share dividends.

Alliance generated an additional $22 million of distributable cash compared to 2014, largely driven by the effects of a weaker Canadian dollar and the discontinuance of rate regulated accounting. A full year of earnings from Ruby, acquired in the fourth quarter of 2014, provided an additional $100 million of distributable cash.

Distributions from Aux Sable decreased by $46 million from 2014 due to the effect of weaker NGL market conditions and negative pipeline capacity margins. Overall, the Veresen Midstream transaction has been neutral to distributable cash, as the reduced contribution from Hythe/Steeprock, resulting from the change in ownership, has been offset by reduced Corporate administrative and interest costs.

Lower distributable cash from our power business in the year compared to 2014 resulted from the sale of our U.S. gas-fired cogeneration facilities in the first quarter of 2015, partially offset by incremental earnings from our Dasque-Middle run-of-river hydro and St. Columban and Grand Valley Phase III wind facilities, which commenced operations in 2015.

2015 Corporate costs were lower than last year, primarily due to lower general and administrative costs driven by the revaluation of our long-term incentive plans.

Current tax in the year was higher due to higher U.S. pipeline earnings and the impact of a weaker Canadian dollar on U.S.-based taxes. Our April 1, 2015 issuance of Series E Preferred Shares resulted in higher Preferred Share dividends in 2015.

Distributable cash increased in the fourth quarter of 2015 due to the same factors discussed above with the exception of the sale of our U.S. gas-fired cogeneration facilities in the first quarter of 2015. These facilities did not have a material impact on fourth quarter 2014 cash flows.

Distributable cash on a per share basis in 2015 was impacted by common shares issued in April and October 2014 to fund our growth initiatives.

## Cash from Operating Activities

| ($ Millions) | Three months ended December 31 2015 | Three months ended December 31 2014 | Year ended December 31 2015 | Year ended December 31 2014 |
|---|---|---|---|---|
| Pipeline | **80** | 58 | **302** | 182 |
| Midstream | **19** | 47 | **94** | 138 |
| Power | **24** | (2) | **74** | 38 |
| Power – operating working capital from discontinued operations | **–** | 7 | **–** | 12 |
| Veresen – Corporate and Project Development | **(47)** | (39) | **(183)** | (155) |
| | **76** | 71 | **287** | 215 |

For the year ended December 31, 2015, we generated $287 million of cash from operating activities compared to $215 million in 2014. Higher operating cash flows during the fourth quarter from our Pipeline business, partially offset by a decrease in our Midstream business, generally reflect the same factors impacting distributable cash, as well as changes in non-cash working capital.

### ACCOUNTING STANDARDS AND BASIS OF PRESENTATION

Our consolidated financial statements as at and for the year ended December 31, 2015 have been prepared by management in accordance with US GAAP. All financial information is in Canadian dollars unless otherwise noted and, as it relates to our financial results, has been derived from information used to prepare our US GAAP consolidated financial statements. Capitalized terms used in this MD&A that have not been defined have the same meanings attributed to them in our 2015 consolidated financial statements. Additional information concerning our business is available on SEDAR at **www.sedar.com** or on our website at **www.vereseninc.com**.

### FORWARD-LOOKING AND NON-GAAP INFORMATION

*Some of the information contained in this MD&A is forward-looking information under Canadian securities laws. All information that addresses activities, events or developments which may or will occur in the future is forward-looking information. Forward-looking information typically contains statements with words such as may, estimate, anticipate, believe, expect, plan, intend, target, project, forecast or similar words suggesting future outcomes or outlook. Forward-looking statements in this MD&A include statements about:*

- *the impact of Alliance's new services framework on Alliance's future earnings;*
- *Aux Sable's ability to realize upon the extraction agreements with producers;*
- *the 2016 pricing environment for ethane and propane;*
- *the timing of the completion of construction and in-service date of the Sunrise and Tower gas plants, the Saturn compression station expansion and the Hythe liquids recovery project;*
- *the projected date for a final investment decision on Jordan Cove LNG and Pacific Connector Gas Pipeline;*
- *the effective elimination of cash taxes for approximately the next five years, excluding Part VI.1 taxes on Preferred Share dividends, as a result of our U.S.-based organizational restructuring*
- *the projected date for commencing LNG production from Jordan Cove LNG;*
- *the sufficiency of our liquidity;*
- *the sufficiency of our available committed credit facilities to fund working capital, dividends and capital expenditures;*
- *the ability of each of our businesses to generate distributable cash and the timing under which distributable cash will be generated; and*
- *our ability to pay dividends.*

*The risks and uncertainties that may affect our operations, performance, development and the results of our businesses include, but are not limited to, the following factors:*

- *our ability to successfully implement our strategic initiatives and achieve expected benefits;*
- *levels of oil and gas exploration and development activity;*
- *status, credit risk and continued existence of contracted customers;*
- *availability and price of capital;*
- *availability and price of energy commodities;*

- *availability of construction services and materials;*
- *fluctuations in foreign exchange and interest rates;*
- *our ability to successfully obtain regulatory approvals;*
- *changes in tax, regulatory, environmental, and other laws and regulations;*
- *competitive factors in the pipeline, midstream and power industries;*
- *operational breakdowns, failures, or other disruptions; and*
- *prevailing economic conditions in North America.*

*Additional information on these and other risks, uncertainties and factors that could affect our operations or financial results are included in our filings with the securities commissions or similar authorities in each of the provinces of Canada, as may be updated from time to time. We caution readers that the foregoing list of factors and risks is not exhaustive. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these factors are independent and management's future course of action would depend on its assessment of all information at that time. Although we believe the expectations conveyed by the forward-looking information are reasonable based on information available to us on the date of preparation, we can give no assurances as to future results, levels of activity and achievements. Readers should not place undue reliance on the information contained in this MD&A, as actual results achieved will vary from the information provided herein and the variations may be material. We make no representation that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained herein are made as of the date hereof, and, except as required by law, we do not undertake any obligation to update publicly or to revise any forward-looking information, whether as a result of new information, future events or otherwise. We expressly qualify any forward-looking information contained in this MD&A by this cautionary statement.*

*Certain financial information contained in this MD&A may not be standard measures under GAAP in the United States and may not be comparable to similar measures presented by other entities. These measures are considered to be important measures used by the investment community and should be used to supplement other performance measures prepared in accordance with GAAP in the United States. For further information on non-GAAP financial measures used by us see the section entitled "Non-GAAP Financial Measures" contained in this MD&A.*

## BUSINESS OVERVIEW

We are a Canadian corporation committed to actively managing and growing our pipeline transportation, midstream services, power generation, and liquefied natural gas businesses. We focus on high-quality, long-life infrastructure assets in North America with diversity in asset type and geography, and which contribute toward stable cash flow generation. Our businesses are underpinned by a prudent capital structure and investment-grade credit ratings.

### Strategy

Our strategy is to continue building the best contracted network of natural gas and NGL infrastructure in our geographic footprint. We are focused on owning the right infrastructure in the right places to support long-term trends in gas and NGL flows and to add value to our customers. In executing this strategy, we adhere to the following key principles:

- Own, build, operate and provide services with natural gas and NGL processing, transportation, and storage infrastructure that best connect competitive supply with high-value markets;
- Focus on primarily fee-based commercial structures that are responsive to customers and generate predictable, long-term earnings and cash flows;
- Pursue focused growth within our existing footprint, which gives us a strong competitive advantage;
- Consistently deliver safe and reliable operations, cost control, and effective project development and construction management; and
- Maintain a strong balance sheet and ample liquidity to adapt to market conditions and opportunities, with a prudent capital structure that supports investment grade credit ratings.

Over the last five years, our strategy has materially grown our fee-based cash flows to reduce exposure to Aux Sable, our only business with direct commodity price exposure. A large majority of our distributable cash is now generated from take-or-pay contracts with no volume or commodity price risk.

Our take-or-pay and fee-based cash flows are supported by diverse businesses and long-term contracts. We've improved the diversity and contribution of the fee-based business by:

- Acquiring our preferred interest in the Ruby pipeline in late-2014;
- Creating Veresen Midstream which will drive growth in fee-based cash flow in 2018 and beyond; and
- Growing our Power portfolio, with new renewable resource-based facilities commencing operations in 2015.

## Advancement of Strategy in 2015

In 2015, we made significant progress in the advancement of our strategy, as detailed below.

Alliance

December 1, 2015 marked a significant, new chapter in Alliance's history as it began operating under its new, market-focused service model.

On June 30, 2015 and July 9, 2015, the National Energy Board of Canada ("NEB") and the U.S. Federal Energy Regulatory Commission ("FERC") each approved, as filed by Alliance, the new services and associated terms and conditions, as well as the firm tolls effective December 1, 2015 for the new Canadian and U.S. service offerings, respectively. In addition, regulatory approval was received to change the Hydrocarbon Dewpoint ("HCDP") gas quality specification from -10 degrees Celsius to -5 degrees Celsius, effective December 1, 2015. The new HCDP specification changes in both Canada and the U.S. will enhance shipper access to rich gas transportation and facilitate an increase in the NGL content of the gas Alliance transports.

The approvals allowed Alliance to move forward with its new market-focused services and the conversion of its executed precedent agreements into firm transportation contracts.

Alliance successfully re-contracted its receipt capacity through 2018, and approximately 90% of firm receipt capacity in 2019 and 2020, with average contract lengths of 5.3 years. With demand far in excess of available capacity, Alliance successfully contracted all of its available winter 2015/2016 and summer 2016 seasonal firm capacity, as well as additional short-term firm service contracts with terms up to 90 days to capture this strong demand for transportation service. In December 2015, Alliance's average daily throughput to the Aux Sable inlet was 1.65 bcf/d. This includes the marketing of available interruptible transportation services, resulting in an average of 73 mmcf/d of interruptible receipt service and 77 mmcf/d of interruptible delivery service during the month. Alliance will continue to use its flexible and competitive suite of new services, along with the operational capabilities and reliability of its system, to optimize the physical and economic utilization of its pipeline.

The liquids-rich natural gas transported on the Alliance pipeline under the new contracts increase the need for NGL fractionation capacity at Aux Sable's Channahon facility. As a result, the owners of Aux Sable, including us, approved the construction of a 24,500 barrels per day expansion of the fractionation facility, which is expected to be in service in mid-2016.

Alliance's new services offerings are further discussed in the *Description of Business – Pipeline Business – Alliance Pipeline* section of this MD&A.

Veresen Midstream LP

On December 22, 2014, a new entity, Veresen Midstream Limited Partnership ("Veresen Midstream"), was formed, which is jointly owned and controlled by us and affiliates of Kohlberg Kravis Roberts & Co. L.P. ("KKR"), a global investment firm. On March 31, 2015, we funded our interest in Veresen Midstream by contributing our Hythe/Steeprock gathering and processing assets. Veresen Midstream also closed the acquisition of natural gas gathering and compression assets in the Dawson area of northeastern British Columbia from Encana Corporation ("Encana") and the Cutbank Ridge Partnership ("CRP") on March 31, 2015. As part of this transaction, Veresen Midstream agreed to undertake up to $5 billion of new midstream expansion for Encana and CRP in the Montney region over a five year period. CRP is a partnership between Encana and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation.

All infrastructure acquired and to be developed associated with this transaction, collectively the "Dawson Assets", is supported by 30-year fee-for-service arrangements with Encana and CRP. Veresen Midstream is our primary growth vehicle for our Canadian natural gas and NGL midstream business.

Veresen Midstream established us as a leading player in the core of the Montney, one of North America's most prolific and competitive resource plays. The partnership required no up-front funding from us as it was funded initially through non-recourse debt and a cash contribution from KKR, while we funded our initial investment by contributing our Hythe/Steeprock assets. The definitive agreements provide Veresen Midstream with a large multi-year capital program to construct contracted midstream infrastructure under favourable economic terms, and a powerful platform to pursue additional third-party growth opportunities.

On October 6, 2015, CRP sanctioned the 400 mmcf/d Sunrise gas plant. The estimated capital cost for the project (plant and ancillary facilities) is $860 million (gross). Construction of the Sunrise gas plan is now underway. On December 7, 2015, CRP sanctioned the $715 million (gross) 200 mmcf/d Tower rich gas processing complex, which is the second major new gas plant now under construction. Both Sunrise and Tower are expected to be in service in late 2017.

On March 9, 2016, we announced the sanctioning of the 200 mmcf/d Saturn compression station expansion ("Saturn Phase II"). The estimated cost of the fully contracted expansion project is $930 million (gross) with an anticipated in-service date in mid-2018. Veresen Midstream is also advancing other projects, including enhanced liquids recovery at the Hythe gas processing facility which was recently sanctioned. The enhanced liquids recovery project is expected to be in-service during the third quarter of 2016 with an estimated capital cost of $25 million (gross).

The Veresen Midstream transaction and expansion projects are further discussed in the *Description of Business – Midstream Business – Veresen Midstream* section of this MD&A.

Burstall Ethane Storage Facility

We will build and operate a new wholly-owned ethane storage facility located near Burstall, Saskatchewan, approximately 20 kilometres north of the Empress NGL complex. The salt cavern facility will have capacity to store approximately 1 million barrels of ethane, and will be connected via pipeline to our Alberta Ethane Gathering System. The expected capital cost of the storage facility and related infrastructure is approximately $140 million. The Burstall facility will provide our customers with valuable operational storage as ethane imports to Empress from the North Dakota Bakken grow.

We have entered into an agreement with NOVA Chemicals Corporation ("NOVA") where NOVA will use the majority of the storage capacity under a 20-year arrangement. Subject to final regulatory approvals, the facility is expected to be in service in the second half of 2018. Once operational, we expect the storage facility to provide stable cash flows, comprised largely of fixed payments which are not dependent on utilization levels.

Jordan Cove LNG Development Project

During 2015, we continued to make steady progress in advancing the development of our Jordan Cove LNG and Pacific Connector Gas Pipeline ("Pacific Connector") projects. On September 30, 2015, the FERC issued a final Environmental Impact Statement ("EIS") for Jordan Cove LNG and Pacific Connector, marking a significant regulatory milestone. We expect the FERC to issue a final order and certificate for Jordan Cove LNG and Pacific Connector in due course. We are comfortable with the mitigation conditions recommended in the conclusions of the final EIS.

Financing Strategy

During 2015 we undertook a number of steps to strengthen our liquidity, reduce borrowing costs and reduce leverage. On March 31, 2015 we used the $420 million in cash we received from Veresen Midstream to partially repay our Acquisition Credit Facility related to the Ruby acquisition in the fourth quarter of 2014. On April 1, 2015 we issued 8.0 million Cumulative Redeemable Preferred Shares, Series E ("Series E Preferred Shares") at a price of $25.00 per share for total gross proceeds of $200 million. Proceeds from our issuance of the Series E Preferred Shares were further used to repay a portion of the Acquisition Credit Facility.

On July 31, 2015, our Revolving Credit Facility was increased from $550 million to $750 million and the term extended such that it now matures on May 31, 2019. In August 2015, we drew from our Revolving Credit Facility to repay the remaining outstanding balance of the Acquisition Credit Facility.

As a result of the above activities, we reduced our debt to total capitalization ratio from 42% to 26% over the course of the year.

## DESCRIPTION OF BUSINESS

### Pipeline Business

Our Pipeline business represented 58% of our total asset base as at December 31, 2015 and is comprised of:

- Alliance Pipeline (50% ownership);
- Ruby Pipeline (50% convertible preferred ownership) and
- Alberta Ethane Gathering System ("AEGS") (wholly-owned).

Ruby and AEGS are stable cash flow generators that are supported by take-or-pay transportation agreements. Alliance has re-contracted all of its year-round firm receipt capacity through 2018, and approximately 90% of firm capacity in 2019 and 2020, with average contract durations of 5.3 years.

#### *Alliance Pipeline*

Alliance owns and manages an integrated, high-pressure natural gas and natural gas liquids pipeline that extends approximately 3,000 kilometres across North America. The system is capable of transporting 1.65 billion cubic feet per day of liquids-rich natural gas. With an extensive gathering system, Alliance delivers natural gas from the gas-rich regions of northeastern British Columbia and northwestern Alberta to delivery points near Chicago, Illinois, a major natural gas market hub. At its terminus, the Alliance pipeline connects with five interstate natural gas pipelines and two local natural gas distribution systems with an aggregate of over 6 billion cubic feet per day of production physically connected into the Pipeline. These connected pipelines and local distribution systems serve major natural gas consuming areas in the midwestern United States and Ontario. The Alliance pipeline also connects at its terminus with Aux Sable's extraction facility, in which we hold a 42.7% ownership interest.

Alliance's new services offering, effective December 1, 2015, includes full-path service from Canadian receipt points to the delivery point at the Canada-USA border, and on to the delivery points near Chicago via the US leg of the pipeline. Segmented services are also offered, including the option of nominating volumes from a Canadian receipt point, in one of two zones, to the new Canadian Alliance Trading Pool ("ATP"). These services offer shippers competitive fixed tolls for terms out to ten years, and biddable tolls for interruptible and seasonal firm service. The design of the new services offering also includes rich gas services and the ability to stage contract commitments.

Alliance's new services include the following key service elements:

- ATP – a new Canadian trading pool allowing receipt and delivery shippers to trade gas. The ATP is a notional point connecting the receipt zones to the delivery zone (which extends from the ATP to the Canada-USA border), where the Canadian portion of the pipeline connects with the US leg of the pipeline. The introduction of the ATP facilitates the segmentation of services on the pipeline into receipt and delivery services, providing a platform for receipt and delivery shippers to transfer title and allowing shippers to access Term Park and Loan services.
- Firm Receipt Service includes two zones with fixed volumetric tolls, allowing shippers to move gas from their contract receipt point(s) to the ATP. Firm receipt shippers will also have access to a Priority Interruptible Transportation Service (PITS) that can provide additional transportation access as production volumes grow. PITS is available to Firm Receipt Service shippers with terms of three years or more and allows them to flow up to 25% more volume at their contracted receipt points.
- Firm Delivery Service allows shippers to deliver gas from the ATP to the Canada-USA border. Fixed tolls are offered on one to ten year contract terms.
- Firm Full Path Service is volumetrically tolled service from Canadian receipt points to Chicago with fixed tolls.

Pipeline Abandonment Costs

The NEB Land Matters Consultation Initiative is an initiative that requires NEB regulated pipelines to set aside funds to cover future abandonment costs. The NEB provided several key guiding principles under this initiative, including the position that abandonment costs are legitimate costs of providing transportation services and are recoverable, upon NEB approval, from shippers.

Alliance collects abandonment funds through a pipeline abandonment demand surcharge. These funds are set aside in a trust until such time that the funds are required to settle abandonment-related expenditures.

### *Ruby Pipeline*

Ruby is a large-scale natural gas transmission system delivering U.S. Rockies natural gas production to markets in the western United States. The 680-mile, 42-inch pipeline has a current capacity of approximately 1.5 bcf/d, with expansion potential to 2.0 bcf/d through the addition of compression. Ruby originates at the Opal hub in Wyoming and extends to the Malin hub in Oregon. The Malin hub is the main interconnect to the proposed Pacific Connector Gas Pipeline (50% owned by us), which would supply our proposed Jordan Cove LNG terminal. El Paso Pipeline Partners, an affiliate of Kinder Morgan Inc., holds the remaining 50% ownership interest in Ruby through a common equity interest. Kinder Morgan, North America's largest natural gas pipeline operator, operates Ruby on a day-to-day basis.

Long-term take-or-pay contracts are in place with a strong mix of investment grade shippers for approximately 1.1 bcf/d with a weighted average remaining contract term of approximately seven years.

### *AEGS*

AEGS is an integrated pipeline system that transports purity ethane from various Alberta ethane extraction plants to major petrochemical complexes located near Joffre and Fort Saskatchewan, Alberta. The system also transports ethane to and from third party underground storage in Fort Saskatchewan. Expansion projects commissioned in 2012 near Fort Saskatchewan increased the overall length of AEGS to 1,330 km. These projects included additional pipeline and metering to directly connect AEGS to the major petrochemical complex in Fort Saskatchewan, and the installation of a new pipeline leg for the receipt of ethane from Aux Sable's Heartland Off-gas facility.

AEGS' revenues and earnings are based on long-term, take-or-pay ethane transportation agreements, referred to as "ETAs", which extend to December 31, 2018. The ETAs provide for a minimum revenue stream based on specified committed volumes and the recovery of all operating costs.

## Midstream Business

As at December 31, 2015, our Midstream business represented 17% of total assets.

### *Veresen Midstream*

On March 31, 2015, we funded our interest in Veresen Midstream by contributing our Hythe/Steeprock gathering and processing assets valued at $920 million, and in exchange received from Veresen Midstream $420 million in cash, resulting in a 50% equity position valued at $500 million. KKR funded its 50% interest in Veresen Midstream by contributing $500 million in cash.

Veresen Midstream closed the acquisition of natural gas gathering and compression assets in the Dawson area of northeastern British Columbia from Encana and CRP on March 31, 2015. The aggregate purchase price of the acquisition was approximately $760 million, comprised of approximately $435 million for operating compression facilities and pipelines, $155 million for work in progress associated with the Saturn compressor station, and $170 million for other work in progress, including the Sunrise and Tower gas plants and additional gas gathering pipelines. All infrastructure acquired and to be developed associated with this transaction is supported by 30-year fee-for-service arrangements with Encana and CRP.

On March 31, 2015, Veresen Midstream closed a US$575 million drawn Term Loan B and established $1,350 million in credit facilities. Proceeds from these facilities, which are non-recourse to us, were used to fund the initial acquisition of assets from Encana and CRP, as well as ongoing construction.

Veresen Midstream will fund approximately 55% to 60% of the construction costs of the Sunrise, Tower and Saturn gas plants with its existing $1.275 billion credit facility and additional non-recourse debt at the partnership level, with the balance to be contributed over time by us and KKR. We are funding and intend to fund the majority of our share of future contributions to Veresen Midstream with ongoing proceeds received from equity issued in connection with our Premium Dividend™ and Dividend Reinvestment Plan.

Veresen Midstream is currently comprised of:

- Hythe Processing Facility, with 176 mmcf/d of sour gas processing capacity and 340 mmcf/d of sweet gas processing capacity. It is connected to the Alliance and TransCanada gas pipeline systems. The Hythe facility includes a sulphur plant with a capacity of approximately 120 tonnes/d;
- Steeprock Processing Facility, with capacity of 198 mmcf/d, is connected to the Hythe gas plant and the Alliance and TransCanada natural gas pipeline systems;
- Gathering and Compression System, consisting of 900 km of gas gathering lines and 100,000 horsepower of compression operated by Encana on behalf of Veresen Midstream;
- Saturn Compression Station ("Saturn Phase I"), with 200 mmcf/d of compression capacity, which commenced operations in June 2015 ahead of schedule and under budget at a cost of $155 million;
- Tower Gas Plant, a 200 mmcf/d facility under construction with an anticipated in-service date in late 2017 and an expected cost of $715 million;
- Sunrise Gas Plant, a 400 mmcf/d facility under construction with an anticipated in-service date in late 2017 and an estimated cost of $860 million; and
- Saturn Phase II, representing an additional 200 mmcf/d of compression and 400 mmcf/d of refrigeration, with an anticipated in-service date in mid-2018 and an expected cost of $930 million.

Hythe/Steeprock earnings are primarily generated from a long-term take-or-pay midstream services agreement, referred to as the "Hythe/Steeprock MSA", entered into on February 9, 2012 with Encana. The Hythe/Steeprock MSA provides for minimum monthly fees based on specific committed volumes and unit fees, as well as the recovery of operating and maintenance costs. Volume commitments and unit fees are adjusted annually based on a pre-determined schedule to reflect anticipated production profiles and moderate fee escalation.

Dawson earnings, representing the Gathering and Compression System, Saturn Phase I and gas plants currently under construction, are and will be primarily generated from fee-for-service agreements. Under these agreements, unit capital fees are set for individual components in order to achieve a target rate of return based on invested capital and expected throughput. Facility fees will be fixed 12 months after commercial operations, and gathering fees will be reset at defined periods based on actual throughput. These and other contract mechanisms are in place to provide strong expected returns on capital, with downside financial protection. One such downside protection is a potential payout of minimum costs associated with certain gathering and compression assets. The potential payout of minimum costs will be assessed in the eighth year of the assets' service period and is based on whether there is an overall shortfall of total system cash flows from natural gas gathered and compressed under certain service agreements. The potential payout amount can be reduced in the event Veresen Midstream markets unutilized capacity to third party users.

All of our and half of KKR's Veresen Midstream equity is held in partnership units that are eligible to receive cash distributions. The remaining half of KKR's initial equity investment is in the form of payment-in-kind ("PIK") units which do not receive cash distributions and instead accrete at a rate equal to the cash yield on the remaining equity plus 4% per year. The PIK units are convertible to cash-paying units after four years from the initial issuance at either KKR's or our option.

This structure provides us with a disproportionately higher share of cash flow during the construction period, prior to the Sunrise and Tower gas plants being placed in-service. The transaction has been neutral to our distributable cash in 2015 and is expected to be accretive as new capital projects are placed in-service. We and KKR will have equal governance rights in Veresen Midstream so long as either partner's equity interest remains above 35%.

### *Aux Sable*

Aux Sable is comprised of:

- Aux Sable Liquid Products (42.7% ownership), which owns the Channahon Facility, a world-scale NGL extraction and fractionation facility near the terminus of the Alliance pipeline, capable of recovering up to 107,000 barrels per day of ethane, propane, normal butane, iso-butane and natural gasoline;
- Aux Sable Midstream (42.7% ownership), which owns the following assets:
  - the Palermo Conditioning Plant in the Bakken region of North Dakota, with a processing capacity to 80 mmcf/d, which removes the heavier hydrocarbon compounds from the rich gas delivered into the Prairie Rose Pipeline, while leaving the majority of the natural gas liquids;
  - the Prairie Rose Pipeline, a 12-inch diameter, 133-km (83-mile) pipeline with an estimated capacity of 110 mmcf/d, which gathers liquids-rich gas from the Palermo Plant and other sources for delivery into the Alliance pipeline system; and
  - storage facilities, downstream NGL pipelines and loading facilities adjacent to the Channahon facility;
- Aux Sable Canada (50% ownership), which owns:
  - NGL injection facilities on the Alliance pipeline in Alberta and B.C.;
  - a minority interest in the Septimus and Wilder Gas Plants, two natural gas processing plants with a processing capacity of 75 mmcf/d and 60 mmcf/d, respectively, located in the liquids-rich Montney region of British Columbia;
  - the Septimus Pipeline, a 20-km pipeline capable of delivering 400 mmcf/d of natural gas from the Septimus Gas Plant to the Alliance pipeline; and
  - the Heartland Off-gas Facility, an off-gas processing facility located in Fort Saskatchewan, Alberta; and
- Alliance Canada Marketing (42.7% ownership), which holds long-term firm natural gas transportation capacity on the Alliance pipeline used for balancing makeup gas for Aux Sable's Channahon Facility.

Pursuant to a long-term NGL Sales Agreement with BP Products North America Inc., Aux Sable sells all production from its Channahon Facility to BP. In return, BP pays Aux Sable a fixed annual fee and a percentage share of net margins in excess of the fixed fee. The percentage share of net margins varies and depends upon specified thresholds being reached. In addition, BP compensates Aux Sable for all associated operating and maintenance costs, and subject to certain limits, costs incurred to source feedstock gas supply and capital costs associated with its Channahon Facility.

Aux Sable Midstream's Palermo Conditioning Plant and Prairie Rose Pipeline in the Bakken earns processing and pipeline transportation fees, respectively, and retains a margin on the NGLs recovered.

As part of Aux Sable's strategy to attract liquids-rich natural gas to its Channahon Facility for the period following December 1, 2015, efforts were focused on working with producers who were developing liquids-rich fields in the Montney and Duvernay which were not yet connected to the Alliance Pipeline system. Aux Sable offered Rich Gas Premium agreements which include sharing natural gas liquids margins with producers. These agreements allow producers to avoid immediate capital investment and provide NGL value tied to large, liquid U.S. Midwest markets.

Aux Sable Canada may have gas positions in multiple locations on the Alliance pipeline as a result of the RGP agreements. In conjunction with its RGP agreement contracting, Aux Sable has developed gas marketing, transportation and commercial arrangements to support and manage the supply of liquids-rich natural gas to the Channahon Facility. This business may involve Aux Sable purchasing and selling natural gas and/or holding transportation on Alliance pipeline or adjacent transportation systems, in order to mitigate potential exposure to commodity prices or basis differentials.

Aux Sable has executed several Rich Gas Premium agreements and, as a result, Aux Sable's ability to extract additional NGLs at the Channahon Facility has reached the plant's current capacity. In response to customer demand, the owners of Aux Sable, including us, approved an expansion of the Channahon Facility which will allow for approximately 24,500 barrels per day of additional fractionation capacity, over and above the plant's current nameplate capacity of 107,000 barrels per day. The Channahon Facility expansion, which will increase the propane and butane processing capacity, has an estimated capital cost of US$130 million (gross). In November 2015, Aux Sable entered into an agreement with a third party for the sale of substantially all of the expanded propane capacity.

## Power Business

We have grown our Power business through greenfield development and acquisitions into a diverse portfolio of power generation facilities capable of generating 888 MW (gross). A significant portion of our power facilities is underpinned with long-term capacity payment-based energy contracts that provide stable cash flows not significantly influenced by commodity prices or volumes of electricity generated. Our power assets represented 23% of our total asset base as determined at December 31, 2015 and are comprised of (wholly-owned except where stated otherwise):

- Gas-fired generation and district energy
  - York Energy Centre generation facility in Ontario (400 MW; 50% ownership);
  - East Windsor cogeneration facility in Ontario (86 MW);
  - London cogeneration and district energy facility in Ontario (17 MW);
  - P.E.I. Energy Systems, a district energy facility in Charlottetown, P.E.I.;
- Waste heat
  - two EnPower facilities in B.C. (10 MW);
  - four NRGreen facilities in Saskatchewan (20 MW; 50% ownership) and one in Alberta (13 MW; 50% ownership);
- Run-of-river hydro
  - Glen Park in New York (33 MW);
  - Furry Creek in B.C. (11 MW; 99% ownership);
  - Upper and Lower Clowhom in B.C. (22 MW);
  - Dasque-Middle in B.C. (20 MW);
- Wind power
  - Grand Valley phases I, II and III in Ontario (9 MW, 11 MW and 40 MW, respectively; 75% ownership); and
  - St. Columban in Ontario (33 MW; 90% ownership).

### *Gas-fired and District Energy Facilities*

Each of our gas-fired generation facilities in Ontario sells capacity and electricity pursuant to long-term power purchase agreements with investment-grade counterparties. The power purchase agreements are structured to pay the facilities contracted rates for having capacity available and for the recovery of fuel costs. As a result, earnings and cash flows from the facilities are realized primarily by capacity payments and are not significantly impacted by the volume of electricity produced or by commodity price fluctuations. In addition to capacity payments, the majority of these facilities have the opportunity to earn energy margins.

Our district energy systems in Ontario and Prince Edward Island consist of central production plants which convert fuel (such as natural gas, municipal waste, biomass and fuel oil) into steam, hot water and/or chilled water. These products are distributed through underground pipes to customers' buildings to provide heating, air conditioning and some industrial process uses.

On January 8, 2015, we closed the sale of our gas-fired generation facilities located in Colorado and California for a sale price of US$27 million.

### *Renewables*

Waste Heat Facilities

Our waste heat facilities in Saskatchewan, Alberta and British Columbia use Energy Recovery Generation (ERG®) technology and waste heat generated by certain Alliance and Spectra pipeline compressor stations. Electricity generated in Saskatchewan and British Columbia is sold to Saskatchewan Power Corporation and to BC Hydro, respectively, under long-term power purchase agreements. NRGreen, in which we hold a 50 percent ownership interest, completed the 13-MW Whitecourt, Alberta waste heat power generation facility, and commenced operations on December 8, 2014. Electricity generated from the Whitecourt facility is sold into the Alberta Power Pool on a spot basis.

Run-of-River Facilities

We own four run-of-river hydroelectric facilities in British Columbia with an aggregate 53 MW of generation capacity. These facilities sell power to BC Hydro under long-term electricity purchase agreements. We are paid for the volume of electricity actually delivered based on fixed, inflation-escalated prices. The Dasque-Middle run-of-river hydro facility was placed into commercial service on May 21, 2015.

Our portfolio of run-of-river facilities also includes the 33-MW Glen Park facility, located in upstate New York. Glen Park sells all of its output at prevailing market terms on a month-to-month basis.

Wind Power Facilities

We hold a 75% ownership interest in the Ontario-based Grand Valley wind facilities, which sell power to the Ontario Power Authority (OPA) under long-term contracts. Phase III commenced operations on December 4, 2015.

The St. Columban wind project commenced operations on July 16, 2015.

## RESULTS OF OPERATIONS – BY BUSINESS SEGMENT

### Pipeline Business

| | Three months ended December 31, 2015 | | | | Three months ended December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|---|
| ($ Millions, except where noted) | **Total** | Alliance | Ruby[3] | AEGS | Total | Alliance | Ruby[3] | AEGS |
| **Equity income** | **34** | 34 | – | – | 26 | 26 | – | – |
| **Dividend income** | **31** | – | 31 | – | 16 | – | 16 | – |
| **Earnings before interest, tax depreciation and amortization ("EBITDA")**[1] | **6** | – | – | 6 | 7 | – | – | 7 |
| Depreciation and amortization | **(3)** | – | – | (3) | (4) | – | – | (4) |
| Interest and other finance | **(1)** | – | – | (1) | (1) | – | – | (1) |
| **Net income before tax** | **67** | 34 | 31 | 2 | 44 | 26 | 16 | 2 |
| **Distributable cash** | **83** | 47 | 31 | 5 | 57 | 36 | 16 | 5 |
| **Volumes (100%)** | | **1.481 bcf/d** | **1.013 bcf/d** | **279.6 mbbls/d**[2] | | 1.547 bcf/d | 0.845 bcf/d | 296.8 mbbls/d[2] |

| | Year ended December 31, 2015 | | | | Year ended December 31, 2014 | | | |
|---|---|---|---|---|---|---|---|---|
| ($ Millions, except where noted) | **Total** | Alliance | Ruby[3] | AEGS | Total | Alliance | Ruby[3] | AEGS |
| **Equity income** | **131** | 131 | – | – | 112 | 112 | – | – |
| **Dividend income** | **116** | – | 116 | – | 16 | – | 16 | – |
| **Earnings before interest, tax depreciation and amortization ("EBITDA")**[1] | **28** | – | – | 28 | 28 | – | – | 28 |
| Depreciation and amortization | **(14)** | – | – | (14) | (14) | – | – | (14) |
| Interest and other finance | **(5)** | – | – | (5) | (5) | – | – | (5) |
| **Net income before tax** | **256** | 131 | 116 | 9 | 137 | 112 | 16 | 9 |
| **Distributable cash** | **302** | 167 | 116 | 19 | 180 | 145 | 16 | 19 |
| **Volumes (100%)** | | **1.488 bcf/d** | **0.805 bcf/d** | **285.6 mbbls/d**[2] | | 1.556 bcf/d | 1.020 bcf/d | 289.1 mbbls/d[2] |

(1) This item is not a standard measure under US GAAP and may not be comparable to similar measures presented by other entities. See section entitled *"Non-GAAP Financial Measures"* in this MD&A.

(2) Average daily volumes for AEGS are based on toll volumes.

(3) We acquired the 50% convertible preferred interest in Ruby Pipeline on November 6, 2014.

### *Alliance Pipeline*

Operational Highlights

Transportation deliveries for the year ended December 31, 2015 averaged 1.488 bcf/d, compared to 1.556 bcf/d in 2014. After the implementation of the new services model on December 1, 2015, transportation deliveries averaged 1.65 bcf/d for the month of December, reflecting strong demand for interruptible service. Alliance also contracted 73 mmcf/d of interruptible receipt service and 77 mmcf/d of interruptible delivery service through a bidding process in December. Toll rates for interruptible service ranged from 108% to 129% of firm rates.

On August 7, 2015, the Alliance Pipeline system was shut down for approximately one week following the detection of hydrogen sulphide ("H2S") that entered the system as a result of complications experienced by an upstream operator. During that time, Alliance reduced the amount of H2S in the pipeline to a safe level through flaring within the confines of Alliance's Alameda compressor station in Saskatchewan. Alliance followed regulatory procedures and took additional precautionary measures to protect people, the site and the surrounding area. Monitoring stations were installed to ensure that air quality standards were being met. The incident did not damage or impact the integrity of the pipeline system.

Financial Highlights

Distributable cash for the year ended December 31, 2015 was $167 million compared to $145 million in 2014. The increase was largely driven by a weaker Canadian dollar, higher negotiated depreciation rates applicable to the first 11 months of 2015 and the discontinuance of rate regulated accounting.

Net income before tax for the year ended December 31, 2015 was $131 million compared to $112 million for 2014. The increases primarily reflect the same factors impacting distributable cash, partially offset by the impact of the H2S shutdown. The financial impact of the shutdown was not material to us. Alliance is pursuing avenues for the recovery of the costs associated with this incident.

Fourth quarter results reflect the same factors discussed above excluding the H2S shutdown which impacted third quarter earnings. December results were impacted by lower toll rates under the new services model, partially offset by lower operating costs.

### *Ruby Pipeline*

Operational Highlights

Long-term ship-or-pay contracts are in place for approximately 1.1 bcf/d, or 71%, of the pipeline's capacity, 90% of which are held by investment grade shippers. The average remaining length of the contracts is over seven years. Transportation deliveries for the year ended December 31, 2015 averaged 0.805 bcf/d compared to 1.020 bcf/d in 2014. Volumes are lower than the contracted levels as a result of downstream pipeline maintenance, mild weather and less demand for volumes into storage.

Financial Highlights

Distributable cash and net income for the year ended December 31, 2015 was $116 million representing annual distributions we are entitled to as holders of the convertible preferred interest. Distributable cash and net income for the year ended December 31, 2014, was $16 million, representing our portion of the annual distributions from the date of acquisition.

### *AEGS*

Operational Highlights

Toll volumes for the year ended December 31, 2015 were 285.6 mbbls/d, consistent with volumes of 289.1 mbbls/d for 2014.

Financial Highlights

For the year ended December 31, 2015, AEGS generated $19 million in distributable cash and $9 million in net income before tax, consistent with last year's results.

## Midstream Business

| ($ Millions, except where noted) | Three months ended December 31, 2015 | | | | Three months ended December 31, 2014 | | |
|---|---|---|---|---|---|---|---|
| | Total | Hythe/ Steeprock | Veresen[1] Midstream | Aux Sable | Total | Hythe/ Steeprock | Aux Sable |
| **Equity income (loss)** | **(18)** | – | 2 | (20) | 13 | – | 13 |
| **EBITDA** | **–** | – | – | – | 18 | 18 | – |
| Depreciation and amortization | **–** | – | – | – | (10) | (10) | – |
| **Net income (loss) before tax** | **(18)** | – | 2 | (20) | 21 | 8 | 13 |
| **Distributable cash** | **19** | – | 15 | 4 | 34 | 17 | 17 |
| **Volumes (100%)** | | | | | | | |
| Hythe/Steeprock[2] | | **–** | **391.9** | | | 400.8 | |
| Dawson[3] | | **–** | **709.0** | | | – | |
| Ethane | | | | **26.5** | | | 21.0 |
| Propane plus | | | | **46.1** | | | 46.7 |
| | | **–** | **1,100.9** | **72.6** | | 400.8 | 67.7 |
| | | **mmcf/d** | **mmcf/d** | **mbbls/d** | | mmcf/d | mbbls/d |

| ($ Millions, except where noted) | Three months ended December 31, 2015 | | | | Three months ended December 31, 2014 | | |
|---|---|---|---|---|---|---|---|
| | Total | Hythe/ Steeprock | Veresen[1] Midstream | Aux Sable | Total | Hythe/ Steeprock | Aux Sable |
| **Equity income (loss)** | **(44)** | – | (1) | (43) | 48 | – | 48 |
| **EBITDA** | **21** | 21 | – | – | 73 | 73 | – |
| Depreciation and amortization | **(10)** | (10) | – | – | (40) | (40) | – |
| **Net income (loss) before tax** | **(33)** | 11 | (1) | (43) | 81 | 33 | 48 |
| **Distributable cash** | **76** | 20 | 45 | 11 | 131 | 74 | 57 |
| **Volumes (100%)** | | | | | | | |
| Hythe/Steeprock[2][4] | | **393.8** | **392.6** | | | 399.9 | |
| Dawson[3][4] | | **–** | **634.1** | | | – | |
| Ethane | | | | **21.4** | | | 22.6 |
| Propane plus | | | | **45.1** | | | 47.6 |
| | | **393.8** | **1,026.7** | **66.5** | | 399.9 | 70.2 |
| | | **mmcf/d** | **mmcf/d** | **mbbls/d** | | mmcf/d | mbbls/d |

(1) Veresen Midstream results are for the applicable periods from April 1 to December 31, 2015.

(2) Hythe/Steeprock fee volumes represent (i) either the minimum commitment volumes for which we earned processing fees or actual volumes processed if in excess of the minimum threshold in respect of the Midstream Services Agreement with our primary customer, and (ii) fees for volumes processed for other producers.

(3) Dawson throughput volumes represent actual volumes processed from our primary customer.

(4) Veresen Midstream volumes include volumes from Hythe/Steeprock and Dawson from April 1 to December 31, 2015.

### *Hythe/Steeprock*

In the first quarter of 2015, the Hythe/Steeprock assets, while wholly owned by us, generated $20 million of distributable cash and $11 million of net income prior to the Veresen Midstream transaction closing on March 31, 2015. Results for the last nine months of the year for the Hythe/Steeprock assets form part of Veresen Midstream's results, discussed below.

## *Veresen Midstream*

Operating and financial results of the Hythe/Steeprock assets within Veresen Midstream exclude first quarter results when they were wholly owned by us.

The net book value of the Hythe/Steeprock assets contributed by us to fund our interest in Veresen Midstream on March 31, 2015 was $839 million, resulting in a pre-tax gain on sale to $37 million attributable to the monetary portion of the transaction.

### Operational Highlights

During the fourth quarter of 2015, actual volumes received from Encana and CRP at Dawson averaged 709.02 mmcf/d, compared to 584.7 mmcf/d and 607.8 mmcf/d during the second and third quarters respectively. The increased throughput is a result of the resolution of bottleneck issues in the northern part of Dawson. Reduced throughput volumes in the southern portion of Dawson resulting from integrity maintenance-related curtailments imposed by downstream pipelines were resolved by the end of the fourth quarter.

Fee volumes at Hythe/Steeprock averaged 391.9 mmcf/d and 392.9 mmcf/d for the three and twelve months ending December 31, 2015. Fee volumes are comprised of the minimum volume commitment under the Hythe/Steeprock MSA and natural gas from third party producers. Compared to the same periods last year, the Hythe/Steeprock fee volumes decreased two percent in line with the contractual commitment. During the three and twelve months ending December 31, 2015, the Hythe and Steeprock facilities operated at reliability factors of 99.8% and 99.9%, respectively, exceeding their respective target factors under the MSA.

To fund the initial acquisition of assets from Encana and CRP, as well as ongoing construction, Veresen Midstream had fully drawn its US$575 Term Loan B and $370 million from its $1,275 million expansion credit facility as at December 31, 2015. By the end of the year, Veresen Midstream had invested $312 million in the Sunrise and Tower facilities.

### Financial Highlights

| | Three months ended December 31 | Nine months ended December 31 |
|---|---|---|
| (Veresen's share; $ Millions) | **2015** | **2015** |
| Hythe/Steeprock EBITDA | **10** | **30** |
| Dawson EBITDA | **10** | **23** |
| Corporate general and administrative | **(2)** | **(5)** |
| Depreciation and amortization | **(9)** | **(26)** |
| Interest and other finance | **(6)** | **(19)** |
| Unrealized loss on translation of US dollar debt | **(12)** | **(37)** |
| Unrealized gain on cross currency swap | **11** | **32** |
| Other foreign exchange | **–** | **1** |
| Net income (loss) before tax / equity income (loss) | **2** | **(1)** |

During the nine months ending December 31, 2015, Veresen Midstream generated $45 million of distributable cash and a net loss of $1 million before tax, in line with expectations.

Hythe/Steeprock and Dawson generated $30 million and $23 million of EBITDA, respectively, for the period ended December 31, 2015. The EBITDA generated by Hythe/Steeprock is mainly comprised of the minimum volume and fee commitment provided by the MSA. Dawson's EBITDA is based on actual throughput being received from Encana and CRP and fee for service revenues governed under a long-term MSA.

On December 31, 2015, Veresen Midstream paid a distribution of $23 million, of which our share is $15 million. The PIK structure allowed us to receive two-thirds of the cash distributions while we were entitled to approximately 49.6% of the net income during the nine months ending December 31, 2015.

Results for the period ending December 31, 2015 include a $32 million fair value gain on Veresen Midstream's cross currency swap, offset by a $37 million foreign exchange loss on the revaluation of Veresen Midstream's US dollar denominated Term Loan (discussed in the *Financial Instruments* section of this MD&A) and the expensing of $2 million of deferred financing costs resulting from the re-pricing of Veresen Midstream's Term Loan in the second quarter. There were no operating earnings or distributions from Veresen Midstream during the first quarter of 2015 as its operating assets, including Hythe/Steeprock, were not acquired until March 31, 2015.

During the fourth quarter of 2015, Veresen Midstream paid a distribution of $15 million. Hythe/Steeprock and Dawson both generated $10 million of EBITDA, and net income includes an $11 million fair value gain on Veresen Midstream's cross currency swaps and an $12 million loss on the revaluation of its US dollar-denominated Term Loan.

### *Aux Sable*

NGL Market Overview

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| | **2015** | 2014 | **2015** | 2014 |
| Average USGC ethane margin (US$/gallon) | **0.03** | (0.05) | **0.03** | (0.02) |
| Average USGC propane plus margin (US$/gallon) | **0.31** | 0.52 | **0.30** | 0.75 |
| Average USGC propane (US$/gallon) | **0.42** | 0.77 | **0.46** | 1.04 |
| Average Henry Hub natural gas (US$/mmbtu) | **2.24** | 3.75 | **2.61** | 4.34 |
| Average Chicago Citygate natural gas (US$/mmbtu) | **2.16** | 3.90 | **2.69** | 5.57 |
| Average WTI crude oil (US$/bbl) | **42.18** | 73.24 | **48.29** | 93.02 |
| Average Chicago-AECO differential ($/mmbtu) | **0.42** | 0.88 | **0.80** | 1.61 |

U.S. Gulf Coast ("USGC") ethane margins remained weak throughout 2015 due to continued oversupply.

Propane inventory levels in the U.S. remained at elevated levels through 2015, depressing USGC propane plus margins relative to 2014. U.S. propane stocks ended 2015 at an estimated 93 million barrels, 21 million barrels above levels from the same period last year and 39 million barrels above the five-year average. Seasonal demand factors such as winter heating and crop drying were insufficient to work down high inventory levels. USGC propane prices averaged US$0.42 per gallon in the fourth quarter of 2015 compared to US$0.77 per gallon during the same period in 2014, reflecting the high inventory levels and downward pressure on natural gas liquids prices stemming from a steep decline in crude oil prices. USGC propane prices for the year decreased US$0.58 compared to 2014.

Natural gas prices declined throughout the fourth quarter of 2015, reflecting high inventory levels resulting from strong North American natural gas production, despite lower prices and persistent warm temperatures during the winter months. The first quarter of 2014 experienced higher gas prices as a result of the extremely cold temperatures in the U.S. Mid-West. The Chicago Citygate gas price averaged US$2.16 per mmbtu during the fourth quarter of 2015, decreasing US$1.74 per mmbtu over the same period last year.

Operational Highlights

During the year ended December 31, 2015, Aux Sable processed 93% of the natural gas delivered by Alliance compared to 96% last year. The decrease primarily relates to bypassing volumes due to high inventory volumes, uneconomic margins and planned downtime.

Receipts into the Prairie Rose Pipeline in North Dakota averaged 101 mmcf/d during the year ended December 31, 2015, compared to 98 mmcf/d for the same period last year. The increase was primarily due to planned volume growth from the Bakken producers and extremely cold temperatures hampering producer field gathering systems early in the first quarter of 2014, partially offset by the August 2015 Alliance pipeline shutdown.

Propane plus sales volumes were 45.1 million mbbls/d for the year ended December 31, 2015 compared to 47.6 mbbls/d last year, driven by reinjection due to oversupply in the market and the Alliance pipeline shutdown in August. Aux Sable produced 21 mbbls/d of ethane during 2015 to satisfy certain commercial arrangements. Volumes in 2015 were lower than last year due to a continued market oversupply of ethane.

Financial Highlights

*Components of Aux Sable Equity Income:*

| (Veresen's share; $ Millions) | Three months ended December 31 **2015** | 2014 | Year ended December 31 **2015** | 2014 |
|---|---|---|---|---|
| Margin based lease revenues | | | | |
| Amount generated during period | **1** | 5 | **4** | 23 |
| Margin recognized from prior period | **–** | 3 | **–** | – |
| (Unrecognized margin in period) | **–** | – | **–** | – |
| Amount recognized as revenue | **1** | 8 | **4** | 23 |
| Pipeline capacity margin | **(6)** | – | **(14)** | 6 |
| Other margin based activities | **1** | 5 | **(2)** | 16 |
| Fixed fee activities | **10** | 9 | **39** | 35 |
| General, administrative, operating and maintenance | **(6)** | (6) | **(23)** | (21) |
| Provision for potential customer settlement | **(16)** | – | **(32)** | – |
| Depreciation and amortization | **(4)** | (3) | **(15)** | (11) |
| Interest and other finance | **–** | – | **–** | – |
| Net income (loss) before tax / equity income (loss) | **(20)** | 13 | **(43)** | 48 |

For the year ended December 31, 2015, Aux Sable generated $11 million of distributable cash and $43 million in net losses before tax, compared to $57 million of distributable cash and $48 million in net income before tax in 2014.

During 2015, Aux Sable's NGL Sales Agreement provided downside protection against the continued weak NGL market environment, delivering the fixed fee and covering the Channahon facility's operating costs with no meaningful margin based lease revenues being generated.

Losses were incurred this year with respect to Aux Sable's pipeline capacity business, due to temporary disruptions in pipeline takeaway capacity creating gas market supply demand imbalances during the third and part of the fourth quarter of 2015, and narrowing of the AECO-Chicago natural gas price differential. Last year saw the widening of the AECO-Chicago natural gas price differential in the first quarter of 2014, largely driven by the extreme cold temperatures in the U.S. Mid-West, resulting in higher pipeline capacity earnings in 2014.

Aux Sable's other margin-based activities decreased due to lower NGL fractionation margins realized at its Palermo Conditioning Plant in North Dakota.

In the fourth quarter of 2015, an additional $16 million provision was recognized in respect of potential adjustments relating to Aux Sable customer obligations.

Fourth quarter distributable cash and net income decreased relative to the same period in 2014 due to the same factors discussed above. AECO – Chicago natural gas price differentials narrowed significantly in the fourth quarter of 2015 relative to the same period last year, resulting in losses in Aux Sable's pipeline capacity business.

## Power Business

| ($ Millions, except where noted) | Three months ended December 31 2015 | 2014 | Year ended December 31 2015 | 2014 |
|---|---|---|---|---|
| Gain (loss) on interest rate hedges | **5** | (4) | **(1)** | (12) |
| Other equity income | **3** | 2 | **5** | 10 |
| **Equity Income (loss)** | **8** | (2) | **4** | (2) |
| **EBITDA** | **15** | 9 | **46** | 40 |
| Depreciation and amortization | **(10)** | (7) | **(33)** | (27) |
| Interest and other finance | **(3)** | (3) | **(10)** | (13) |
| Foreign exchange and other | **3** | – | **3** | – |
| **Net income (loss) before tax** | **13** | (3) | **10** | (2) |
| **Distributable cash** | **14** | 8 | **43** | 47 |
| **Volumes (GWh)** | | | | |
| Gross | **190** | 182 | **716** | 766 |
| Net | **156** | 151 | **603** | 638 |

Operational Highlights

Our power facilities performed reliably in 2015. We completed construction of our Ontario-based St. Columban and Grand Valley Phase III wind projects and Dasque / Middle BC run-of-river hydro project during the year; all facilities are operating as expected.

Financial Highlights

For the year ended December 31, 2015, our power facilities generated $43 million of distributable cash, a $4 million decrease compared to last year. The decrease was mainly attributable to the sale of our U.S. gas-fired facilities in January 2015 and the receipt of a $4 million retroactive adjustment in relation to York Energy Centre's power purchase agreement with the Ontario Power Authority ("OPA") during the second quarter of 2014, partially offset by the incremental earnings from our new wind and run-of-river hydro projects commencing operations in 2015.

For the year ended December 31, 2015, net income before tax was $10 million compared to a net loss of $2 million in 2014. Higher operating earnings from our facilities during the year and lower losses on interest rate hedges was partially offset by incremental depreciation on our new facilities and the receipt of the $4 million retroactive adjustment from the OPA in the second quarter of 2014.

Distributable cash for the quarter ending December 31, 2015 increased by $6 million due to incremental cash flows from our new facilities. The U.S. gas-fired facilities sold in the first quarter did not have a material impact on fourth quarter 2014 cash flows. Net income for the quarter ending December 31, 2015 increased due to higher operating earnings and gains on interest rate hedges, partially offset by incremental depreciation on our new facilities.

## Veresen – Corporate and Project Development

| ($ Millions) | Three months ended December 31 2015 | 2014 | Year ended December 31 2015 | 2014 |
|---|---|---|---|---|
| Equity loss | **4** | 4 | **14** | 12 |
| General and administrative | **2** | 7 | **22** | 29 |
| Project development | **29** | 20 | **85** | 79 |
| Depreciation and amortization | **1** | – | **3** | 2 |
| Interest and other finance | **7** | 13 | **38** | 41 |
| Foreign exchange and other | **1** | (35) | **(5)** | (41) |
| **Net expenses before tax** | **44** | 9 | **157** | 122 |
| **Distributable cash** | **(9)** | (18) | **(53)** | (66) |

For the year ended December 31, 2015, we incurred $157 million of net corporate expenses before taxes, a $35 million increase compared to the previous year. The increase was due to a $39 million pre-tax gain on forward foreign exchange contracts entered into to manage the foreign exchange exposure related to the Ruby acquisition in the fourth quarter of 2014 and higher project development spending related to our Jordan Cove LNG project. This was partially offset by lower general and administrative costs driven by the revaluation of our long-term incentive plans.

Interest was lower in the fourth quarter of 2015 due to the repayment of the Acquisition Facility throughout 2015.

### Taxes

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ Millions) | **2015** | 2014 | **2015** | 2014 |
| **Net income from continuing operations before tax** | **18** | 48 | **113** | 103 |
| Current tax | **(6)** | (10) | **(37)** | (30) |
| Deferred tax | **9** | (3) | **18** | 5 |
| **Total tax** | **3** | (13) | **(19)** | (25) |
| **Effective rate** | **(16.7)%** | 27.1% | **16.8%** | 24.3% |

Our effective tax rate for 2015 is lower than in 2014 due to a recovery of prior year foreign taxes and Alliance's discontinuation of rate-regulated accounting. Effective January 1, 2016, we implemented a U.S.-based organizational restructuring which effectively eliminates cash taxes, with the exception of Part VI.1 taxes on our Preferred Share dividends, for approximately the next five years.

## LIQUIDITY AND CAPITAL RESOURCES

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ Millions, except where noted) | **2015** | 2014 | **2015** | 2014 |
| Cash flows | | | | |
| Operating activities | **76** | 71 | **287** | 215 |
| Investing activities | **(24)** | (1,689) | **366** | (1,794) |
| Financing activities | **(105)** | 1,645 | **(658)** | 1,606 |
| | **December 31, 2015** | | December 31, 2014 | |
| Cash and short-term investments | **58** | | 51 | |
| Capitalization | | | | |
| Senior debt[(1)] | **1,100** | **26%** | 1,811 | 42% |
| Shareholders' equity | **3,087** | **74%** | 2,532 | 58% |
| | **4,187** | **100%** | 4,343 | 100% |

(1) Includes current portion of long-term senior debt.

In 2015 we advanced our goal of reducing leverage and borrowing costs and improving liquidity. As discussed below under Equity Financing Activities and Debt Financing Activities, we used cash proceeds from the Veresen Midstream transaction and issuance of preferred shares to repay a portion of the Acquisition Credit Facility. As a result of these transactions, we reduced our debt to total capitalization ratio from 42% at the end of 2014 to 26% at the end of 2015.

We expect to continue to utilize cash from operations, drawings on our Revolving Credit Facility and cash raised through our DRIP to fund liabilities as they become due, finance capital expenditures, fund debt repayments, pay dividends and to provide flexibility for new investment opportunities. As at December 31, 2015, we had $750 million of committed credit facilities of which $169 million was drawn, including $21 million in letters of credit.

At December 31, 2015, we had cash and short-term investments of $58 million (December 31, 2014 – $51 million) and non-cash working capital deficit of $17 million (December 31, 2014 – $22 million excess).

## Investing Activities

For the year ended December 31, 2015, we generated $366 million of cash from investing activities, compared to $1,794 million of cash used in 2014 to fund our investing activities. Significant investing activities for the year ended December 31, 2015 and 2014 are presented in the table below.

| | Year ended December 31 | |
|---|---|---|
| ($ Millions) | **2015** | 2014 |
| Acquisitions and dispositions | | |
| Ruby acquisition, net of gains on forward foreign exchange contracts | – | (1,597) |
| Proceeds from sale of assets | **420** | 19 |
| | **420** | (1,578) |
| Investments in jointly-controlled businesses | | |
| Equity contributions | **(60)** | (74) |
| Return of capital | **30** | 11 |
| | **(30)** | (63) |
| Capital expenditures | | |
| Midstream | **(9)** | (14) |
| Dasque-Middle run-of-river hydro facility | **(6)** | (47) |
| St. Columban wind project | **(29)** | (83) |
| Operating power facilities | **(7)** | (2) |
| Other capital expenditures | **(7)** | (2) |
| | **(58)** | (148) |
| Other | **–** | (1) |
| Cash provided (used) in discontinued operations | **34** | (4) |
| Investing | **366** | (1,794) |

## Financing Activities

For the year ended December 31, 2015, we used $658 million of cash to settle financing obligations, compared to $1,606 million of cash inflows in 2014. Financing activities for the year ended December 31, 2015 and 2014 included:

| | Year ended December 31 | |
|---|---|---|
| ($ Millions) | **2015** | 2014 |
| Common Share dividend payments | **(107)** | (156) |
| Common Share issuance, net of issue costs | **–** | 1,157 |
| Net draws (repayments) on Revolving Credit Facility | **25** | (41) |
| Senior debt repayments | **(738)** | (262) |
| Senior debt issued, net of issue costs | **–** | 920 |
| Preferred Shares issued, net of issue costs | **194** | – |
| Preferred Share dividend payments | **(24)** | (16) |
| Other | **(8)** | 4 |
| Financing | **(658)** | 1,606 |

### Equity Financing Activities

Commencing with the cash dividend payable to shareholders of record on October 31, 2014, eligible shareholders may participate in the Premium Dividend™ component of the Dividend Reinvestment Plan ("DRIP") which will entitle such shareholders to reinvest their dividends in Common Shares issued from treasury and to have such Common Shares exchanged for a premium cash payment equal to 102% of the cash dividend that such shareholders would otherwise be entitled to receive on the applicable dividend payment date. The availability of the Premium Dividend (™ Trademark of Canaccord Genuity Corp.) to shareholders has substantially increased participation in our DRIP program, proving us with additional cash to fund our various growth initiatives.

On April 1, 2015 we issued 8.0 million Cumulative Redeemable Preferred Shares, Series E ("Series E Preferred Shares") at a price of $25.00 per share for total gross proceeds of $200 million.

The Series E Preferred Shares are redeemable by us, in whole or in part, on June 30, 2020 and on June 30 of every fifth year thereafter at a price of $25.00 per share plus accrued and unpaid dividends.

### Debt Financing Activities

On March 31, 2015 we used the $420 million in cash we received from Veresen Midstream to partially repay our Acquisition Credit Facility related to the Ruby acquisition in the fourth quarter of 2014. Proceeds from our April 1, 2015 issuance of the Series E Preferred Shares were used to repay an additional portion of the Acquisition Credit Facility.

On July 31, 2015, our Revolving Credit Facility was increased from $550 million to $750 million and the term extended such that it now matures on May 31, 2019. In August 2015, we drew from our Revolving Credit Facility to repay the remaining $112 million outstanding balance of the Acquisition Credit Facility.

## DIVIDENDS

### *Policy*

Our general dividend policy is to establish and maintain a sustainable and stable monthly dividend, having regard for forecast distributable cash and our growth capital requirements.

We pay dividends on our Common Shares on a monthly basis to common shareholders of record as at the last business day of each month on the 23rd day of the month following such record date, or if not a business day, then on the preceding business day.

The holders of Series A Preferred Shares are entitled to receive fixed cumulative preferential cash dividends at an annual rate of 4.40%, payable quarterly. The dividend rate will reset on September 30, 2017 and every five years thereafter based on then-market rates.

The holders of Series C Preferred Shares are entitled to receive fixed cumulative preferential cash dividends at an annual rate of 5.00%, payable quarterly. The dividend rate will reset on March 31, 2019 and every five years thereafter based on then-market rates.

The holders of Series E Preferred Shares are entitled to receive fixed cumulative preferential cash dividends at an annual rate of 5.00%, payable quarterly. The dividend rate will reset on June 30, 2020 and every five years thereafter based on then-market rates. The holders of Series E Preferred Shares will have the right to convert all or any part of their shares into Cumulative Redeemable Preferred Shares, Series F ("Series F Preferred Shares"), subject to certain conditions, on June 30, 2020, and on June 30 of every fifth year thereafter. The holders of Series F Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by our Board of Directors of Veresen, at a rate based on then-market rates.

### *Sustainability of Dividends and Productive Capacity*

We intend to continue to pay dividends, although such dividends are not guaranteed and do not represent a legal obligation. The sustainability of such dividends is a function of several factors including, among other things:

- earnings and cash flows we generate;
- ongoing maintenance of each business's physical and economic productive capacity;
- our ability to comply with debt covenants and refinance debt as it comes due; and
- our ability to satisfy any applicable legal requirements.

For a complete discussion of the significant risks and uncertainties affecting us, see the *"Risks"* section contained elsewhere in this MD&A.

### *Dividends Paid*

For the year ended December 31, 2015 we declared dividends on our common shares of $291 million (2014 – $227 million), of which $109 million (2014 – $146 million) was paid to common shareholders in cash and $182 million (2014 – $81 million) was paid in Common Shares issued under our DRIP.

### *Restrictions on Dividends*

Our ability to pay dividends to common shareholders is dependent on the applicable terms of certain financing and security agreements. Our Revolving Credit Facility restricts us from paying dividends to common shareholders when an Event of Default has occurred or is continuing. On December 31, 2015 no Event of Default under any of these arrangements had occurred or was continuing that would restrict dividends being paid.

Our investments in our operating businesses have been made through debt and equity investments in subsidiary partnerships and corporations. In general, other than covenant restrictions contained in applicable debt arrangements, there are no legal or practical restrictions on such subsidiary partnerships or corporations from transferring funds received from the operating businesses to us except that the subsidiary corporations must meet liquidity and solvency tests under applicable corporate law.

### *Dividends Paid/Payable Relative to Cash from Operating Activities and Net Income Attributable to Common Shares*

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ Millions) | **2015** | 2014 | **2015** | 2014 |
| Cash from operating activities | **76** | 71 | **287** | 215 |
| Net income attributable to Common Shares | **14** | 21 | **60** | 52 |
| Dividends paid/payable | **73** | 66 | **291** | 227 |
| Less dividends paid in Common Shares under DRIP | **(45)** | (42) | **(182)** | (81) |
| Net dividends paid/payable | **28** | 24 | **109** | 146 |
| Excess of cash from operating activities over net dividends paid/payable | **48** | 47 | **178** | 69 |
| Deficiency of net income attributable to Common Shares over net dividends paid/payable | **(14)** | (3) | **(49)** | (94) |

The excess of cash from operating activities over net dividends paid/payable generally represents the cash we use for maintenance capital expenditures, scheduled amortization of any long-term debt, and cash we retain to fund growth.

Net income attributable to Common Shares is generally less than dividends paid/payable as our net income includes certain non-cash expenses such as depreciation and deferred tax, and can include unrealized foreign exchange and fair value gains and losses which are not reflected in calculating the amount of cash available for the payment of dividends.

## FINANCIAL INSTRUMENTS

We and our jointly-controlled businesses periodically enter into interest rate hedges to manage interest rate exposures. For the year ended December 31, 2015, equity income from our Power business includes a pre-tax $1 million unrealized mark-to-market loss associated with interest rate hedges. For 2014, equity income includes a pre-tax $12 million unrealized mark-to-market loss ($9 million after tax).

During the first quarter of 2015, Veresen Midstream entered into a cross currency swap to manage both interest rate and foreign exchange rate exposures on its US$575 drawn Term Loan B. For the year ended December 31, 2015, equity income from Veresen Midstream includes a pre-tax $32 million unrealized mark-to-market gain ($23 million after tax) associated with the cross currency swap.

The following table summarizes our financial instrument carrying and fair values as at December 31, 2015:

| ($ Millions) | Financial assets at amortized cost | Financial liabilities at at amortized cost | Non-financial instruments | Total | Fair value[1] |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Cash and short-term investments | 58 | | | **58** | 58 |
| Restricted cash | 7 | | | **7** | 7 |
| Distributions receivable | 52 | | | **52** | 52 |
| Accounts receivable and other | 23 | | 5 | **28** | 23 |
| Due from jointly-controlled businesses | 50 | | | **50** | 50 |
| Investments held at cost | 1,981 | | | **1,981** | 2,010 |
| Other assets | 12 | | 1 | **13** | 12 |
| **Liabilities** | | | | | |
| Accounts payable and other | | 65 | | **65** | 65 |
| Dividends payable | | 25 | | **25** | 25 |
| Senior debt | | 1,100 | | **1,100** | 1,143 |
| Other long-term liabilities | | 9 | 27 | **36** | 9 |

(1) Fair value excludes non-financial instruments.

The following table summarizes our financial instrument carrying and fair values as at December 31, 2014:

| ($ Millions) | Financial assets at amortized cost | Financial liabilities at at amortized cost | Non-financial instruments | Total | Fair value[2] |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Cash and short-term investments | 51 | | | **51** | 51 |
| Restricted cash | 5 | | | **5** | 5 |
| Distributions receivable | 46 | | | **46** | 46 |
| Accounts receivable and other | 55 | | | **55** | 55 |
| Due from jointly-controlled businesses | 44 | | | **44** | 44 |
| Assets held for sale | 6 | | 33 | **39** | 6 |
| Investments held at cost | 1,660 | | | **1,660** | 1,660 |
| Other assets | 1 | | 17 | **18** | 1 |
| **Liabilities** | | | | | |
| Accounts payable and other | | 69 | 2 | **71** | 69 |
| Dividends payable | | 8 | | **8** | 8 |
| Liabilities associated with assets held for sale | | 4 | | **4** | 4 |
| Senior debt | | 1,811 | | **1,811** | 1,864 |
| Other long-term liabilities | | 14 | 39 | **53** | 14 |

(2) Fair value excludes non-financial instruments.

For the years ended December 31, 2015 and 2014 the following amounts were recognized in income:

| ($ Millions) | **2015** | 2014 |
|---|---|---|
| Total interest expense, recorded with respect to other financial liabilities, calculated using the effective rate method | **53** | 59 |

## *Fair Values*

Fair value is the amount of consideration that would be agreed upon in an arm's length transaction between knowledgeable, willing parties who are under no compulsion to act.

The fair values of financial instruments included in cash and short-term investments, restricted cash, distributions receivable, receivables and accrued receivables, due from jointly-controlled businesses, other assets, payables, interest payable, accrued payables, dividends payable, and other long-term liabilities approximate their carrying amounts due to the nature of the item and/or the short time to maturity. The fair value of the investment held at cost is based on a number of factors, including the present value of anticipated distributable cash flows to be produced from the underlying operations of the Ruby investment. Assessing these cash flows required the use of assumptions related to the future demand for Ruby's operations, forecasted commodity prices and interest rates, anticipated economic conditions, timing of conversion of the preferred interest into a common equity interest, and other inputs, many of which are not available as observable market data. The fair values of senior debt are calculated by discounting future cash flows using discount rates estimated based on government bond rates plus expected spreads for similarly rated instruments with comparable risk profiles.

US GAAP establishes a fair value hierarchy that distinguishes between fair values developed based on market data obtained from sources independent of the reporting entity, and fair values developed using the reporting entity's own assumptions based on the best information available in the circumstances. The levels of the fair value hierarchy are:

Level 1: Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2: Inputs are other than the quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly.

Level 3: Inputs are not based on observable market data.

We have categorized senior debt as Level 2 and investments held at cost as Level 3.

Financial instruments measured at fair value as of December 31, 2015 were:

| ($ Millions) | Level 1 | Level 2 | Level 3 | **Total** |
|---|---|---|---|---|
| Cash and short-term investments | | 58 | | **58** |
| Restricted cash | | 7 | | **7** |

## *Maturity Analysis of Financial Liabilities*

The tables below summarize our financial liabilities into relevant maturity groupings based on the remaining period at the balance sheet date to the contractual maturity date. The amounts disclosed in the table are the undiscounted cash flows.

The following table summarizes the maturity analysis of financial liabilities as of December 31, 2015:

| ($ Millions) | <1 year | 1-3 years | 4-5 years | Over 5 years |
|---|---|---|---|---|
| Accounts payable and other | **65** | | | |
| Dividends payable | **25** | | | |
| Senior debt | **13** | **640** | **288** | **159** |
| Other long-term liabilities | | **9** | | |

The following table summarizes the maturity analysis of financial liabilities as of December 31, 2014:

| ($ Millions) | <1 year | 1-3 years | 4-5 years | Over 5 years |
|---|---|---|---|---|
| Payables, interest payable and accrued payables | 71 | | | |
| Dividends payable | 8 | | | |
| Liabilities associated with assets held for sale | 4 | | | |
| Senior debt | 11 | 1,174 | 394 | 232 |
| Other long-term liabilities | | 14 | | |

## CONTRACTUAL OBLIGATIONS AND COMMITMENTS

The Court of Appeal for Ontario denied our appeal of a portion of the decision issued earlier this year by an Ontario court in respect of an option held by Energy Fundamentals Group Inc. ("EFG") to acquire up to 20% of our equity interest in the Jordan Cove LNG terminal. We will not appeal this matter further and will determine the information to be provided to EFG in connection with the option in compliance with the terms of the original decision.

On April 15, 2015, Aux Sable received a Notice and Finding of Violation from the United States Environmental Protection Agency ("EPA") for exceedances of permitted limits for Volatile Organic Compounds at Aux Sable's Channahon, Illinois Facility. Aux Sable is engaged in discussions with the EPA to resolve the matter. The initial EPA proposal confirms the settlement amount will not be material.

Payments due for contractual obligations in each of the next five years and thereafter are as follows:

| | | Payments due by period | | | |
|---|---|---|---|---|---|
| ($ Millions) | **Total** | Less than 1 year | 1-3 years | 4-5 years | After 5 years |
| Senior debt | **1,100** | 13 | 640 | 288 | 159 |
| Operating leases | **50** | 6 | 10 | 10 | 24 |
| Other long-term obligations | **37** | 1 | 9 | – | 27 |
| | **1,187** | 20 | 659 | 298 | 210 |

## RISKS

The Company's business objectives, financial condition, future prospects and reputation are impacted by risks and uncertainties. Our objective is to manage these risks and uncertainties in a balanced manner, seeking to mitigate risk while maximizing total shareholder returns. It is senior management's and the applicable business functional head's responsibility to identify and to effectively manage the risks of each business including the development of risk management strategies, policies, processes and systems. Risk management strategies include the use of a prudent third party insurance program, financial and physical hedging of specific risks, and the development of internal policies and practices to optimize functions such as project management, safety, environmental and regulatory compliance, and reputation management. The company is exposed to common business risks as well as business risks associated with our Pipeline, Midstream and Power businesses. Some risks and uncertainties are market-related systemic risks, while others are either common to all of our businesses or unique to our Pipeline, Midstream or Power businesses. The more significant business risks and uncertainties affecting our businesses are set out below.

## Business-Specific Risks

### *Risks Specific to Our Pipeline Business*

Extension of Transportation Contracts; Supply and Demand

Each of Alliance, Ruby, and AEGS derive revenues from transportation contracts with varying terms. Alliance contracts have an average contract term length of five years. Ruby's weighted average primary contract term extends for more than seven years from November 2015. AEGS has primary terms ending in three years. Beyond such terms, the transportation commitments and the associated revenues will depend on various factors, including the supply of, and the demand for, natural gas and ethane for Alliance and AEGS, respectively, produced from western Canada and natural gas produced from the U.S. Rockies for Ruby, and the ability of these pipelines to compete at the supply and demand ends of their respective systems.

Supply depends upon a number of factors including the:

- level of exploration, drilling, reserves and production of natural gas;
- price of natural gas and NGLs;
- price and composition of natural gas available from alternative Canadian and United States sources;
- availability of natural gas in excess of domestic demand for export;
- regulatory environments in Canada and the United States; and
- transportation pricing of competitors.

Demand for natural gas depends, among other things, on weather, price and consumption, and alternative energy sources. Upon maturity of the existing transportation contracts, Alliance and Ruby face competition in pipeline transportation to the Chicago area and Pacific Northwest delivery points, respectively, from both existing pipelines and proposed projects. Any new or upgraded pipelines could either allow shippers and competing pipelines to have greater access to natural gas markets served by Alliance and Ruby and the pipelines to which they are connected. Competitors could further offer natural gas transportation services that are more desirable to shippers than those provided by Alliance or Ruby due to location, facilities or other factors. In addition, competing pipelines could charge rates or provide transportation services to locations that result in greater net profit for shippers, which could result in reduced revenues and cash flows for Alliance and Ruby.

With respect to Alliance, excess natural gas pipeline capacity out of the Western Canadian Sedimentary Basin and a sustained period of low natural gas and crude prices could result in a significant reduction or deferral of investment in upstream gas development, and could negatively impact our ability to re-contract Alliance. Additionally, increased supply from new shale developments including the Marcellus and Utica shale plays could displace gas from the WCSB to the United States Midwest, further increasing re-contracting risk.

With respect to Ruby, the level of commitment for transport on the Ruby pipeline may be negatively affected by reduced supply in the U.S. Rockies due to low natural gas prices. U.S. Rockies natural gas production also has transportation options out of the basin toward the midwestern and northeastern U.S. on competing pipelines. Although current U.S. supply/demand dynamics indicate that future U.S. Rockies supply will favour a U.S. west coast alternative, there is no assurance that U.S. west coast demand and/or U.S. west coast export opportunities will materialize to the degree necessary to ensure that Ruby can access sufficient volumes at sufficient prices to maintain revenues and cash flow. This risk is partially mitigated by our convertible preferred interest ownership in Ruby which provides for a fixed annual distribution before any distributions are made to the holders of common shares.

With respect to AEGS, two large petrochemical companies, each of whom own and operate world-class petrochemical facilities in Alberta, drive the demand for ethane shipped on AEGS. If, for any reason, either of these customers, or their successors, ceased to operate these facilities or otherwise reduced or eliminated the quantities of ethane purchased by them, this could have a negative effect on the quantity of ethane transported on AEGS and our earnings and cash flows. This risk is mitigated by AEGS' take-or-pay contracts with shippers until 2018. Further, AEGS is the only Pipeline in Alberta capable of transporting Ethane.

We can give no assurance as to the abilities of Alliance, AEGS, and Ruby to replace contract commitments from shippers or to negotiate terms similar to those under current transportation contracts upon their expiry.

Rate Regulation

Alliance is subject to Canadian and United States federal regulation by the NEB and the FERC, respectively. AEGS is subject to Canadian provincial regulation by the Alberta Utilities Commission. Ruby is subject to United States federal regulation by the FERC. The ability of our pipelines to generate earnings and cash flows could be adversely affected by changes in pipeline regulation, including:

- changes in interpretations of existing regulations by courts or regulators; and
- any other adverse change to the rates on the respective rate structures or terms and conditions of service.

### *Risk Specific to Alliance and Aux Sable*

Interdependency

There is a significant degree of interdependency between Alliance and Aux Sable, which are related parties through common controlling ownership interests. On one hand, should Aux Sable fail to provide heat content management services to Alliance U.S. for any reason, the Alliance pipeline and its shippers may experience operational issues, including in certain circumstances an interruption or curtailment of transportation service on the Alliance pipeline. On the other hand, the volume and composition of inlet natural gas available to Aux Sable is dependent on the volumes transported on the Alliance pipeline, which is subject to supply and demand factors, including competitive pressures from other pipeline systems, and the operating performance of the Alliance pipeline.

### *Risks Specific to Veresen Midstream*

Natural Gas Throughput

Facilities within Veresen Midstream face the risk of lower throughput due to potential production declines, particularly at times of lower drilling activity in the industry. Earnings and cash flows from the Hythe/Steeprock assets are insulated from volume risk as the long-term Hythe/Steeprock MSA with Encana is a take-or-pay contract. The Dawson Assets have a 30-year fee-for-service arrangement. The risk of lower throughput for the Dawson Assets is mitigated by commercial guarantees including financial protections. Under the arrangement, unit capital fees are set for individual components in order to achieve a target rate of return based on invested capital and expected throughput. Facility fees will be fixed 12 months after commercial operations, and gathering fees will be reset at defined periods based on actual throughput. Another financial protection is a mechanism which provides for the payout of minimum costs associated with certain gathering and compression assets. The potential payout of minimum costs will be assessed in the eighth year of the assets' service period and is based on whether there is an overall shortfall of total system cash flows from natural gas gathered and compressed under certain service agreements. The potential payout amount can be reduced in the event Veresen Midstream markets unutilized capacity to third party users.

Volume risk is mitigated by the continued high level of exploration and development activity in the Montney production area of British Columbia and Alberta, where the Veresen Midstream assets are located, an area widely recognized as one of North America's most promising and competitive natural gas resource plays. In addition, commercial efforts are underway to attract further third party volumes to Veresen Midstream's facilities.

### *Risks Specific to the Power Business*

Gas Supply

The operation of our gas-fired power generation and London district energy facilities requires the delivery of natural gas. If there is any interruption in the provision of natural gas for any of these facilities, the ability to generate electricity and, in the case of the cogeneration facilities, steam or distilled water, will be negatively affected and may have a negative impact on our earnings and cash flows. These facilities are dependent on pipeline deliveries of natural gas and a functioning and integrated North America supply grid. We have attempted to mitigate this risk by purchasing natural gas at major supply hubs and entering into firm delivery contracts with major transporters of natural gas.

### Market Pricing Risks

#### *Commodity Price*

Our earnings and cash flows are subject to movements in certain commodity prices. Our most significant current commodity price exposures are in Aux Sable's midstream business where NGL margins are driven primarily by the relationship between the price of natural gas and the prices of ethane, propane, butane and condensate. Natural gas is the largest cost component of producing specification NGL products. The prices of ethane, propane, butane and condensate are impacted by a variety of factors, including supply and demand for these products, and the price of crude oil. Aux Sable's NGL Sales Agreement is with an international, integrated energy company, which mitigates the downside risk of low NGL prices while retaining significant upside when NGL margins are favourable.

Based on our plan assumptions, if propane plus fractionation spreads strengthen by ten cents per U.S. gallon, or weaken by five cents, the impact on 2016 estimated distributable cash would be $12 million and $(5) million, respectively.

Aux Sable Canada may have gas positions in multiple locations on the Alliance pipeline as a result of the RGP agreements. In conjunction with its RGP agreement contracting, Aux Sable has developed gas marketing, transportation and commercial arrangements to support and manage the supply of liquids-rich natural gas to the Channahon Facility. This business may involve Aux Sable purchasing and selling natural gas and/or holding transportation on Alliance pipeline or adjacent transportation systems, in order to mitigate potential exposure to commodity prices or basis differentials. Basis differentials are impacted by a number of factors, including weather events and forecasts, regional supply/demand dynamics, operational issues on adjacent transportation systems and overall pricing of North American natural gas. Aux Sable continues to implement strategies to minimize the financial impact of these commodity price and basis exposures.

Based on our plan assumptions, if the Chicago-AECO basis differential widens or narrows by US$0.15 per mmbtu, the impact on 2016 distributable cash would be $7 million and $(11) million, respectively.

We are also exposed to movements in energy costs at some of our power facilities where the cost of fuel is not fully recoverable. A significant portion of earnings from our Power business is comprised of fixed capacity payments and, as such, these earnings are not significantly influenced by variability in the commodity price of electricity or natural gas.

To further reduce our exposure to commodity price movements, we may occasionally use derivative instruments, including swaps, futures, and options, to hedge such exposures. These activities are subject to senior management or risk committee oversight as well as specific risk management policies and controls. To the extent these contractual arrangements qualify for hedge accounting treatment, any such gains or losses are recorded in other comprehensive income.

#### *Capital Funding and Liquidity*

To fund our existing businesses and future growth, we rely on cash flows generated by our businesses and on the availability of debt and equity from banks and the capital markets. Conditions within these markets can change dramatically, affecting both the availability and cost of this capital. Higher capital costs directly affect our earnings and cash flows and, in turn, may affect total shareholder returns. To reduce these risks, we prepare forecasts to confirm our capital requirements and adhere to a financing strategy that supports being able to access capital on a timely and cost-effective basis. This strategy includes maintaining:

- a prudent capital structure supported by investment-grade credit ratings. Standard & Poor's Rating Services LLC and DBRS Limited have both recently reaffirmed Veresen's BBB Stable corporate credit ratings; and
- sufficient liquidity through cash balances, excess cash flow, committed revolving credit facilities, and our DRIP to meet our obligations.

Through this strategy, we strive to avoid having to raise additional capital where the costs or terms of which would be regarded as being unfavourable. We have summarized recent changes to the components of our capital in the *Liquidity and Capital Resources* section of this MD&A.

### *Foreign Currency*

Significant portions of our assets, net earnings and cash flows are denominated in U.S. dollars. As a result, their accounting and economic values vary with changes in the U.S./Canadian exchange rate. In 2014, we entered into forward foreign exchange contracts to manage the foreign exchange exposure relating to the Ruby acquisition. To date, we have not entered into any other foreign currency hedges to reduce our currency risk in respect of our net U.S. dollar investment.

We generally use net cash flows from our U.S. operations, supplemented where necessary with U.S. dollar borrowings, to fund our U.S. dollar capital expenditures. From time to time, we have designated U.S. dollar borrowings as a hedge against our U.S. dollar net investment in self-sustaining foreign operations. From an accounting perspective, to the extent these hedges are deemed to be effective, we record any such gains or losses in other comprehensive income.

On December 31, 2015, approximately 61% of our total assets were denominated in U.S. dollars. For the year ended December 31, 2015, we recorded an unrealized foreign exchange gain of $424 million in other comprehensive income on the re-translation of our U.S. net assets. At December 31, 2015, if the Canadian currency had strengthened or weakened by one cent against the U.S. dollar, with all other variables constant, total assets, net income, and distributable cash would have been $20 million, $1 million, and $2 million, respectively, lower or higher.

### *Interest Rate*

We have financed portions of our operations with debt, including floating-rate debt. To the extent interest is not recoverable, we are exposed to fluctuations in interest rates on floating-rate debt and to potentially higher fixed rates at the time existing debt obligations need to be refinanced. To reduce this exposure, we maintain investment-grade credit ratings and generally fund long-term assets utilizing long-term, fixed-rate debt. Our floating-rate debt is primarily comprised of drawdowns under committed bank credit facilities. To reduce our exposure to interest rate fluctuations further, we may occasionally use derivative instruments, including interest rate swaps, collars and forward rate agreements, to hedge against the effect of future interest rate movements. From an accounting perspective, to the extent these hedges are deemed to be effective, we record any such gains or losses in other comprehensive income. On December 31, 2015, 13% of our consolidated long-term debt was floating-rate debt. At December 31, 2015, if interest rates applied to floating-rate debt were 100 basis points higher or lower with all other variables constant, net income before tax and distributable cash each would have been $1 million lower or higher.

As part of York Energy Centre's and Grand Valley's debt financings in 2010 and 2015, respectively, they in aggregate entered into three interest rate hedges. These hedges were entered into to manage the exposure to changes in interest rates whereby York Energy Centre and Grand Valley receive variable interest rates and pay fixed interest rates. As at December 31, 2015, two interest rate hedges remained. Future changes in interest rates will affect the fair value of the remaining hedge, impacting the amount of unrealized gains or losses recognized in the period through equity income. For the three months and twelve months ended December 31, 2015, equity income includes a $5 million unrealized mark-to-market gain and $1 million unrealized mark-to-market loss, respectively, associated with these hedges.

## Common Business Risks

### *Investment*

Our business strategy includes optimizing the value of our existing assets, and developing, constructing and investing in new and existing long-life, high quality energy infrastructure assets. Our ability to achieve accretive growth is influenced by a variety of risks, including:

- the availability of potential projects where we have a strategic advantage;
- securing necessary regulatory and environmental approvals and permits;
- integrating acquisitions in an optimal manner and achieving expected synergies;
- accessing capital on a cost-competitive basis;
- completing late-stage development projects on time and within budget; and
- achieving expected operating and financial performance.

To reduce these risks we utilize our key personnel and outside experts, where necessary, to perform a detailed assessment of the risks and rewards associated with all significant investments. We also use a structured project gate process that ensures that a detailed risk assessment is performed, and the use of detailed financial modeling and an assessment of the project's impact on our financial results, risk profile and capital structure. Senior management and the applicable board of directors review every significant investment to ensure it meets our key investment criteria. These activities require substantial management expertise and resources, which, from time to time, may strain our ability to manage existing operations and possibly other strategic growth opportunities. Periodic assessments of previous investments are undertaken to enhance our execution of future growth initiatives.

***Counterparty***

Through the course of operating our businesses and managing our financial risks, we are exposed to counterparty risks. We are exposed to market pricing and credit-related risks in the event any counterparty, whether a customer, debtor, financial intermediary or otherwise, is unable or unwilling to fulfill their contractual obligations or where such agreements are otherwise terminated and not replaced with agreements on substantially the same terms.

Our trade credit exposures are spread across a diversified set of counterparties, a significant number of which are currently investment-grade entities operating within the energy sector and are subject to the normal credit risks associated with this sector. In most cases, the contractual arrangements with our customers and the related exposures are long-term in nature.

Over the past year, energy prices have seen significant declines and volatility that affected companies throughout the oil and gas industry. A reduction in producers' capital and operating budgets and the impact of reduced revenues on corporate liquidity positions has resulted in an increase in potential credit risk to Alliance and Ruby. There is a risk that suitable replacement shippers could not be found. Requiring shippers to provide letters of credit or other suitable security, unless the shippers maintain specified credit ratings or a suitable financial position, mitigates Alliance's and Ruby's exposure. As at December 31, 2015, 58% of firm capacity on the Alliance pipeline is contracted to shippers who either have an investment grade rating or acceptable credit status. Ruby's largest shipper is a major Northern Californian utility. Investment-grade shippers represent 90% of Ruby's contracted capacity.

In the case of AEGS, we are primarily dependent on two customers, both large petrochemical companies with world-scale petrochemical facilities located in Alberta. AEGS represents a critical component in securing ethane feedstock for these petrochemical facilities. In the case of Veresen Midstream, we are currently dependent on Encana and CRP, a partnership between Encana and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation. Mitsubishi possesses an investment-grade credit rating. Encana is currently rated as investment grade with Standard & Poor's (BBB) and Dominion Bond Rating Service (BBB), while Moody's Investor Service has rated Encana as Ba2. In the case of Aux Sable's midstream business, earnings and cash flows are primarily dependent upon the long-term NGL Sales Agreement with one of the largest integrated energy companies in the world. The counterparty exposures associated with our power business are diverse and are spread across numerous entities (including a number of government entities in the case of our district energy, gas-fired and BC run-of-river hydro facilities), and individual counterparties with investment-grade ratings.

We undertake additional measures to manage our credit risks. These measures are generally guided by short-term investment policies and counterparty credit policies and include:

- assessing the financial strength of new and existing counterparties;
- setting limits on exposures to individual counterparties;
- seeking collateral where appropriate; and
- using contractual arrangements that permit netting of exposures associated with a single counterparty as well as other remedies.

### *Operations*

All of our businesses are subject to risks in the operation of their facilities. Operating risks include:

- the breakdown or failure of equipment, information systems or processes;
- the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects);
- failure to maintain adequate supplies of spare parts;
- operator error; and
- labour disputes, fires, explosions, fractures, acts of terrorists and saboteurs, and other similar events, many of which are beyond our control.

The occurrence or continuance of any of these events could reduce earnings and cash flows.

Our businesses employ various inspection and monitoring methods to manage the integrity of our facilities and to minimize system disruptions. Further, we and our businesses maintain safety policies, disaster recovery procedures and third party insurance coverage at industry acceptable levels in the case of an incident. However, there can be no assurance that these measures will be effective in preventing events that adversely impact the operations of our businesses or that insurance proceeds will be adequate to cover lost earnings and cash flows.

### *Competition*

All of our businesses participate in competitive markets and compete with other companies. Substantially all of our businesses have entered into long-term contractual agreements with varying maturities that serve to reduce the potential impact of this competition. However, we can give no assurances that such agreements will remain in effect or will be replaced with agreements on substantially the same terms. As a result, our future earnings and cash flows are exposed to competitive market forces, particularly at the time any of our existing contracts mature.

We also compete with other businesses for growth and business opportunities, which could impact our ability to grow through acquisitions.

### *Environmental, Health and Safety*

Our businesses are subject to extensive federal, provincial, state, and local environmental, health and safety laws and regulations typical for the industries and jurisdictions within which they operate, including requirements for compliance obligations pertaining to discharges to air, land and water. Our facilities could experience environmental, health and safety incidents including spills, emission exceedances, or other unplanned events that could result in:

- fines or penalties;
- operational interruptions;
- physical injury to our employees, contractors, or general public;
- environmental contamination clean-up costs; and
- additional costs being incurred to achieve compliance.

We are also exposed to potential changes in future laws and regulations, such as those related to nitrous oxides and greenhouse gas emissions, which could result in more stringent and costly compliance requirements.

The Alberta government announced changes to their Specified Gas Emitters Regulation (SGER) in June of 2015, which maintained its requirement that facilities annually emitting 100,000 tonnes or more of greenhouse gas emissions ("GHG") reduce their site-specific emissions intensity by 12%. However, this target increases to 15% as of January 1, 2016 and 20% as of January 17, 2017. Alliance has mitigated the impacted of the SGER program by building a system that is more modern and efficient than older, conventionally designed natural gas pipelines. While GHG emissions have been reduced by using high efficiency gas turbines, achieving the mandated GHG reductions will be difficult to achieve without the need to either purchase Alberta Climate Change Fund credits at $15 per credit (1 credit = 1 tonne of $CO_2$ emission reductions) or to purchase offsets from qualified projects.

The cost to purchase such credits is not expected to be material to us. At present, the change to SGER will not have an impact on AEGS and Veresen Midstream's Hythe gas processing facility as these facilities annually emit less than 100,000 tonnes of GHGs.

We are not aware of any other federal, provincial or state regulations governing GHG emissions that would materially impact our facilities at this time.

Our businesses may also be subject to opposition by special interest groups which could result in schedule delays and increased costs. These special interest groups have the ability to participate in various regulatory processes and proceedings in an effort to influence the outcome.

As part of the consultative process, our businesses work with Aboriginal groups, local landowners, special interest groups, counties, and municipalities. Stakeholder engagement is aimed at providing interested members of the public with information regarding our businesses and addresses their concerns. Stakeholder consultation does not assure that all risks associated with community opposition can be mitigated.

On April 15, 2015, Aux Sable received a Notice and Finding of Violation from the EPA for exceedances of permitted limits for Volatile Organic Compounds at Aux Sable's Channahon, Illinois Facility. Aux Sable is engaged in discussions with the EPA to resolve the matter. The initial EPA proposal confirms the settlement amount will not be material. We are unaware of any other outstanding orders, fines, penalties or litigation for our businesses related to EH&S.

The EH&S Committee reports to our Board of Directors to provide corporate oversight regarding EH&S compliance for our businesses. Alliance and Aux Sable also have EH&S Committees which report to their respective board of directors. Through regular reporting, the EH&S Committees ensure compliance with our EH&S corporate policy, including compliance with all applicable laws and regulations and maintaining a healthy and safe work environment for our employees, and the communities within which we operate. To support this commitment, we have established policies, programs, and practices, including performance targets and reporting to senior management. Our policies, programs and practices are managed by experienced personnel and periodically reviewed and modified to ensure they comply with current laws, regulations, and industry practices.

***Abandonment***

Each of our businesses is responsible for monitoring and complying with all laws and regulations concerning the abandonment of its facilities at the end of their respective economic lives and are therefore exposed to the costs associated with any future such abandonment. The costs of abandonment will be a function of then applicable regulatory requirements, which we cannot accurately predict. Where reasonably determinable, we accrue the costs associated with these legal obligations.

***Insurance***

In the normal course of managing our businesses, we purchase and maintain insurance coverage to reduce certain risks with limits and deductibles that are considered reasonable and prudent, with insurers consistent with industry best practice Our insurance does not cover all eventualities because of customary exclusions and/or limited availability and in some instances, our view that the cost of certain insurance coverage is excessive in relation to the risk or risks being covered. Further, there can be no assurance insurance coverage will continue to be available on commercially reasonable terms, that such coverage will ultimately be sufficient, or that insurers will be able to fulfill their obligations should a claim be made.

***Joint Ownership***

Many of our businesses and material assets are jointly held and are governed by partnership and shareholder agreements. As a result, certain decisions regarding these businesses require a simple majority, while others require 100% approval of the owners. While we believe we have prudent governance and contractual rights in place, there can be no assurance that we will not encounter disputes with partners that may impact operations or cash flows.

***Third Party Operators***

Certain of our assets are operated by unrelated third party entities. The business success of these assets is to some extent dependent on the expertise and ability of these entities to successfully operate and maintain the assets. While we rely on the judgement and operating expertise of these operators, we mitigate this risk by exercising prudent management oversight and relying on operators that have proven track records of success in operating like assets.

### *Development Risk*

In the normal course of business growth, we participate in the design, construction and operation of new facilities. In developing new projects, we may be required to incur significant preliminary engineering, environmental, permitting and legal-related expenditures prior to determining whether a project is feasible and economically viable. In the event a project is not completed or does not operate at anticipated performance levels, we may be unable to recover our investment. There is a risk that projects under development or construction may not be completed on time, on budget or at all. Projects may have delays or increased costs due to many factors.

From time to time, due to long lead times required for ordering equipment, we may place orders for equipment and make deposits thereon or advance projects before obtaining all requisite permits and licenses. We only take such actions where we reasonably believe such licenses or permits will be forthcoming in due course prior to the requirement to expend the full amount of the purchase price. However, any delay in permitting or failure to obtain the necessary permits could adversely affect our earnings and cash flows.

Projects are approved for development on a project-by-project basis after considering strategic fit, the inherent risks, and expected financial returns. A structured gating process that evaluates projects at various stages in the development process is conducted for every project. We believe this approach to project development, combined with an experienced management team, staff and contract personnel, minimizes development costs and execution risk.

## CRITICAL ACCOUNTING POLICIES

Alliance's collection of abandonment costs is subject to rate regulation in Canada. Our consolidated financial statements are prepared in accordance with US GAAP, which include specific provisions applicable to rate-regulated businesses, such as Alliance. As a consequence, these principles may differ from those used by non-rate-regulated entities. In order to achieve a proper matching of revenues and expenses, certain revenues and expenses were recognized in equity income from Alliance differently than would otherwise be expected under US GAAP applicable to non-regulated businesses.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of our consolidated financial statements requires us to make judgements, estimates and assumptions about future events when applying US GAAP that affect the recorded amounts of certain assets, liabilities, revenues and expenses. These judgements, estimates and assumptions are subject to change as the events occur or new information becomes available. The following highlights our more significant accounting estimates. Readers should also refer to note three of our consolidated financial statements for more detailed disclosures of our significant accounting policies.

### *Impairment of Long-lived Assets, Investments in Jointly-Controlled Businesses and Investments Held at Cost*

We evaluate, at least annually, our long-lived assets, investments in jointly-controlled businesses and investments held at cost for impairment when events or changes in circumstances indicate, in our judgement, the carrying value of such assets may not be recoverable. If we determine the recoverability of the asset's carrying value has been impaired, the amount of the impairment is determined by estimating the fair value of the assets and recording a loss for the amount the carrying value exceeds the estimated fair value. Judgements and assumptions are inherent in the determination of the recoverability of such assets and the estimate of their fair value.

On January 8, 2015, we closed the sale of our gas-fired generation facilities located in Colorado and California for a sale price of US$27 million. As a result, we recognized a $12 million impairment loss in the fourth quarter of 2014. We also recognized a $5.0 million impairment loss on land we hold in Ontario.

We did not recognize any impairments of our long-lived assets, investments in jointly-controlled businesses or investments held at cost in 2015.

### *Asset Retirement Obligation*

The estimated fair value of legal obligations associated with the retirement of tangible long-lived assets is to be recognized in the period in which they are incurred if a reasonable estimate of a fair value can be determined. The asset retirement cost, deemed to be the fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived assets and is amortized over the remaining life of these assets. This amortization is included in depreciation and amortization in the consolidated statement of income. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion expense in depreciation and amortization in the consolidated statement of income and comprehensive income, over the estimated time period until settlement of the obligation. Actual expenditures incurred are charged against the accumulated asset retirement obligation.

We have recognized provisions for asset retirement obligations in our consolidated financial statements with respect to the AEGS pipeline system, Veresen Midstream, and the EnPower, East Windsor Cogeneration, Furry Creek, Clowhom and St. Columban power facilities.

With respect to our jointly-controlled businesses, Aux Sable's Septimus and Heartland facilities, and the NRGreen and Grand Valley power facilities have each recognized provisions for asset retirement obligations. Aux Sable has not recognized a provision for asset retirement obligations in respect of its U.S.-based assets as the expected legal obligations are not material. Alliance has not recognized an asset retirement obligation provision for the Alliance pipeline. It is not currently possible to make a reasonable estimate of the fair value of the liability for the Alliance pipeline due to the indeterminate timing and scope of the asset retirement. The NEB's Abandonment Funding Initiative, previously discussed in the *Description of Business* section of this MD&A, addresses the need for a collection method for funding pipeline abandonment costs. The NEB's initiative is not a method for determining the timing of retirement obligations. However, in the event the initiative results in a reasonable estimate of asset retirement obligations for accounting purposes, financial statement recognition of those obligations may be made in future periods. As a result, regulatory assets and liabilities may be recognized to the extent the timing of recovery from shippers differs from the recognition of abandonment costs for accounting purposes. We believe it is reasonable to assume that all asset retirement obligations associated with the Alliance pipeline will be recoverable through future tolls.

### *Depreciation and Amortization*

Our pipeline, plant and other capital assets and intangible assets are depreciated and amortized based on their estimated useful lives. A change in the estimation of useful lives could have a material impact on our consolidated net income.

## NEW ACCOUNTING STANDARDS

Effective January 1 2015, we adopted Accounting Standards Update ("ASU") 2014-08 *"Presentation of Financial Statements and Property, Plant, and Equipment: Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity"*. This ASU provides guidance for changes in criteria and enhanced disclosures for reporting discontinued operations. This guidance was applied prospectively and did not have a material impact.

In May 2014, the FASB issued ASU 2014-09, *"Revenue from Contracts with Customers"*. This ASU provides guidance for changes in criteria for revenue recognition from contracts with customers. This guidance is effective for annual and interim periods beginning after December 15, 2016, and is to be applied retrospectively. In August 2015, the FASB issued ASU 2015-014, *"Revenue from Contracts with Customers: Deferral of the Effective date"*. This ASU amends the effective date of Update 2014-09 for all entities by one year. We are currently evaluating the impact of the standard.

In June 2014, the FASB issued ASU 2014-10, *"Development Stage Entities: Elimination of Certain Financial Reporting Requirements, Including an Amendment to Variable Interest Entities Guidance in Topic 810, Consolidation"*. This ASU eliminates the concept of a development-stage entity from US GAAP along with the associated presentation and disclosure requirements for development-stage entities. The removal of the development stage entity reporting requirements is effective for annual reporting periods beginning after December 15, 2014 and is not expected to have a material impact to us. The consolidation guidance was also amended to eliminate the development stage entity relief when applying the variable interest entity model and evaluating the sufficiency of equity at risk. We are currently evaluating the impact of the amendment to the consolidation guidance, which is effective for annual reporting periods beginning after December 15, 2015. The new standard requires these amendments be applied retrospectively.

In November 2014, the FASB issued ASU 2014-16, *"Derivatives and Hedging."* This ASU provides guidance to clarify the criteria in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. This guidance is effective for annual and interim periods beginning after December 15, 2015, and is to be applied prospectively. We are currently evaluating the impact of the standard.

In January 2015, the FASB issued ASU 2015-01, *"Income Statement – Extraordinary and Unusual Items"*. This ASU simplifies income statement classification by removing the concept of extraordinary items from US GAAP. This guidance is effective for annual and interim periods beginning after December 15, 2015, and may be applied prospectively or retrospectively. We are currently evaluating the impact of the standard.

In February 2015, the FASB issued ASU 2015-02, *"Consolidation: Amendments to the Consolidation Analysis"*. This ASU amends the current consolidation guidance, specifically the guidance in determining whether or not an entity is a variable interest entity. This guidance is effective for annual and interim periods beginning after December 15, 2015, and may be applied on a full or modified retrospective basis. We are currently evaluating the impact of the standard.

In April 2015, the FASB issued ASU 2015-03, *"Interest – Simplifying the Presentation of Debt Issuance Costs"*. This ASU changes the presentation of debt issue costs in financial statements. Under the ASU, an entity presents such costs in the balance sheet as a direct reduction from the related debt liability rather than as an asset. Amortization of the costs is reported as interest expense. This guidance is effective for annual and interim periods beginning after December 15, 2015, and is to be applied retrospectively. We are currently evaluating the impact of the standard.

In June 2015, the FASB issued ASU 2015-010, *"Technical Corrections and Improvements"*. This ASU represent changes to clarify the Codification, correct unintended application of guidance, or make minor improvements to the Codification that are not expected to have a significant effect on current accounting practice. This guidance is effective for annual and interim periods beginning after December 15, 2015. We are currently evaluating the impact of the standard.

In November 2015, the FASB issued ASU 2015-017, *"Income Taxes: Balance Sheet Classification of Deferred Taxes"*. This ASU changes the classification of deferred tax liabilities and assets. Under the ASU, an entity classifies deferred tax liabilities and assets as non-current in the statement of financial position. This guidance is effective for annual and interim periods beginning after December 15, 2016 and is to be applied on a retrospective or prospective basis. The standard is not expected to have a material impact.

In January 2016, the FASB issued ASU 2016-01, *"Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Liabilities"*. This ASU addresses certain aspects of the guidance regarding recognition, measurement, presentation and disclosure of financial instruments, specifically the guidance for measuring the fair value of equity investments. This guidance is effective for annual and interim periods beginning after December 15, 2017, and is to be applied by means of a cumulative-effect adjustment to the Statement of Financial Position as of the beginning of the fiscal year of adoption, with amendments related to equity securities without readily determinable fair values to be applied prospectively. We do not expect the standard to have a material impact.

In February 2016, the FASB issued ASU 2016-02, *"Leases"*. This ASU addresses the recognition, measurement, presentation and disclosure in the financial statements of the assets and liabilities related to operating leases. This guidance is effective for annual and interim periods beginning after December 15, 2018. We are currently evaluating the impact of the standard.

## NON-GAAP FINANCIAL MEASURES

Certain financial measures referred to in this MD&A are not measures recognized under US GAAP. These non-GAAP financial measures do not have standardized meanings prescribed by US GAAP and therefore may not be comparable to similar measures presented by other entities. We caution investors not to construe these non-GAAP financial measures as alternatives to other measures of financial performance calculated in accordance with US GAAP. We further caution investors not to place undue reliance on any one financial measure.

We provide the following non-GAAP financial measures to assist investors with their evaluation of us, including their assessment of our ability to generate distributable cash to fund monthly dividends. We consider these non-GAAP financial measures, together with other financial measures calculated in accordance with US GAAP, to be important factors that assist investors in assessing performance.

**Distributable Cash** – represents the cash we have available for distribution to common shareholders after providing for debt service obligations, Preferred Share dividends, and any maintenance and sustaining capital expenditures. Distributable cash does not include distribution reserves, if any, available in jointly-controlled businesses, project development costs, or costs incurred in conjunction with acquisitions and dispositions. Project development costs are discretionary, non-recoverable costs incurred to assess the commercial viability of greenfield business initiatives unrelated to our operating businesses. We consider acquisition and disposition costs, including associated taxes, to be unrelated to our operating businesses. Operating cash flows provided by our jointly-controlled businesses in the form of operating loans are included in distributable cash. The investment community uses distributable cash to assess the source and sustainability of our dividends.

The amount of distributable cash we earn is comprised of and will vary depending on:

- distributions received/receivable from our jointly-controlled businesses and cash flows from our wholly-owned and majority-controlled businesses, which, in each case, are after providing for scheduled amortization of long-term debt and capital expenditures that are not growth-oriented or recoverable;
- operating support payments required by each of our businesses;
- cash taxes and financing costs we incur, including scheduled principal repayments on long-term debt;
- our general and administrative costs; and
- cash we hold in reserve.

The following is a reconciliation of distributable cash to cash from operating activities.

### Reconciliation of Distributable Cash to Cash From Operating Activities

| | Three months ended December 31 | | Year ended December 31, 2015 | |
|---|---|---|---|---|
| ($ Millions) | **2015** | 2014 | **2015** | 2014 |
| Cash from operating activities | **76** | 71 | **287** | 215 |
| Add (deduct): | | | | |
| Project development costs(1) | **29** | 20 | **85** | 79 |
| Change in non-cash working capital and other | **(3)** | (13) | **(19)** | (2) |
| Principal repayments on senior notes | **(3)** | (3) | **(12)** | (12) |
| Maintenance capital expenditures | **(2)** | (1) | **(4)** | (6) |
| Distributions earned greater (less) than distributions received(2) | **3** | (2) | **(3)** | (5) |
| Preferred Share dividends | **(7)** | (4) | **(24)** | (16) |
| Distributable cash | **93** | 68 | **310** | 253 |

(1) Represents costs incurred by us in relation to projects where the recoverability of such costs has not yet been established. Amounts incurred for the three months and year ended December 31, 2015 relate primarily to the Jordan Cove LNG terminal project, the Pacific Connector Gas Pipeline project, and various other development projects.

(2) Represents the difference between distributions declared by jointly-controlled businesses and distributions received.

**Distributable Cash per Common Share** – reflects the per common share amount of distributable cash calculated based on the average number of common shares outstanding on each record date.

**EBITDA** – refers to earnings before interest, tax, depreciation and amortization. EBITDA is reconciled to net income before tax by deducting interest, depreciation and amortization, and asset impairment losses, if any. The investment community uses this measure, together with other measures, to assess the source and sustainability of cash distributions.

**Adjusted Net Income attributable to Common Shares** – represents net income adjusted for specific items that are significant, but are not reflective of our underlying operations. Specific items are subjective, however, we use our judgement and informed decision-making when identifying items to be included or excluded in calculating adjusted net income. Specific items may include, but are not limited to, certain income tax adjustments, gains or losses on sales of assets, certain fair value adjustments, and asset impairment losses. We believe our use of adjusted net income attributable to Common Shares provides useful information to us and our investors by improving the ability to compare financial results among reporting periods, and by enhancing the understanding of our operating performance and our ability to fund distributions. The following is a reconciliation of adjusted net income attributable to Common Shares to net income attributable to Common Shares.

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| ($ Millions) | **2015** | 2014 | **2015** | 2014 |
| Adjusted net income attributable to Common Shares | **15** | 9 | **66** | 25 |
| Extraordinary loss, net of tax(1) | **–** | – | **(10)** | – |
| Midstream – gain on sale of assets(2) | **–** | – | **37** | – |
| Midstream – unrealized loss on revaluation of Veresen Midstream debt(3) | **(12)** | – | **(37)** | – |
| Midstream – unrealized gain on Veresen Midstream cross currency swap(4) | **11** | – | **32** | – |
| Midstream – write-down of deferred financing costs(5) | **–** | – | **(2)** | – |
| Midstream – potential customer settlement(6) | **(16)** | – | **(32)** | – |
| Power – loss from discontinued operations before tax(7) | **–** | (16) | **–** | (16) |
| Power – unrealized gain (loss) on interest rate hedge(8) | **5** | (4) | **(1)** | (12) |
| Power – one time York OPA settlement(9) | **–** | – | **–** | 4 |
| Corporate – gain on sale of assets(10) | **–** | – | **–** | 14 |
| Corporate – gain on forward foreign exchange contracts | **–** | 34 | **–** | 39 |
| Corporate – asset impairment loss(11) | **–** | (5) | **–** | (5) |
| Taxes(12) | **5** | 3 | **5** | 3 |
| Effect of corporate tax rate changes(13) | **6** | – | **2** | – |
| **Net income attributable to Common Shares** | **14** | 21 | **60** | 52 |

Net income attributable to Common Shares includes the following items which are non-operating in nature and/or unusual items and which we do not expect to recur:

(1) Loss due to the de-recognition of regulatory assets and liabilities related to Alliance.

(2) Gain on the sale of the Hythe/Steeprock assets to Veresen Midstream on March 31, 2015.

(3) Loss on the revaluation of US dollar-denominated Term Loan B held by Veresen Midstream.

(4) Gain on the Veresen Midstream cross currency swap entered into to hedge the impact of changes in foreign exchange and interest rates on the Term Loan B held by Veresen Midstream.

(5) Adjustment to deferred financing costs related to fees incurred on a modification to Veresen Midstream's debt.

(6) Provision recognized in 2015 in respect of potential adjustments relating to Aux Sable customer obligations.

(7) Results relating to U.S. gas-fired assets that were sold January 8, 2015.

(8) Gain (loss) on revaluation of interest rate hedges held by York Energy Centre and Grand Valley Wind Farms.

(9) Retroactive adjustment received in relation to York Energy Center's purchase agreement with the OPA.

(10) Gains on the sale of the Culliton Creek run-of-river development project and our 50% interest in Alton Gas Storage.

(11) Impairment of land we own in Ontario.

(12) The related taxes on the adjusting items described above.

(13) Impact of increased corporate income tax rate in the province of Alberta and a lower rate in the U.S. due to a U.S.-based organizational restructuring.

## SELECTED QUARTERLY FINANCIAL INFORMATION

| | 2015 | | | | 2014 | | | |
|---|---|---|---|---|---|---|---|---|
| ($ Millions, except where noted) | **Q4** | Q3 | Q2 | Q1 | Q4 | Q3(1) | Q2(1) | Q1(1) |
| Operating revenues | **40** | 38 | 37 | 72 | 68 | 68 | 79 | 87 |
| Net income (loss) attributable to Common Shares | **14** | 8 | (12) | 50 | 21 | 3 | (3) | 31 |
| Net income (loss) per Common Share ($) | | | | | | | | |
| – basic and diluted | **0.05** | 0.03 | (0.04) | 0.17 | 0.08 | 0.01 | (0.01) | 0.16 |
| Distributable cash | **93** | 71 | 65 | 81 | 68 | 55 | 64 | 66 |
| Distributable cash per Common Share ($) | | | | | | | | |
| – basic and diluted | **0.31** | 0.25 | 0.22 | 0.28 | 0.26 | 0.24 | 0.29 | 0.33 |
| Cash from operating activities | **76** | 77 | 101 | 33 | 71 | 50 | 49 | 45 |

(1) Comparative figures in this table have been reclassified. See Note 5 in our December 31, 2014 consolidated financial statements

Significant items that affected quarterly financial results include the following:

- Fourth quarter 2015 reflects a continuation of low fractionation margins at Aux Sable and higher Jordan Cove-related spending.
- Third quarter 2015 reflects lower earnings from Aux Sable driven by low fractionation margins.
- Second quarter 2015 reflected lower earnings from Aux Sable driven by low fractionation margins and the provision recognized relating to Aux Sable customer obligations.
- First quarter 2015 reflected a full quarter of Ruby distributions and higher Jordan Cove-related project development costs.
- Fourth quarter 2014 reflected new distributions received from Ruby, higher Jordan Cove-related project development costs and lower earnings from Aux Sable driven by weak commodity prices.
- Third quarter 2014 reflected lower earnings from Aux Sable and higher Jordan Cove related project development costs.
- Second quarter 2014 reflected lower earnings from Aux Sable and higher project development costs.
- First quarter 2014 reflected higher earnings from Aux Sable.

## RELATED PARTY TRANSACTIONS

On March 30, 2012, we provided a $47 million amortizing term loan to Grand Valley, a jointly-controlled business. Principal and interest are payable on a quarterly basis. The loan bears interest of 5.2% and the maturity date is December 31, 2031. At December 31, 2015, the outstanding balance was $42 million (2014 – $44 million).

## DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures are designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President & Chief Executive Officer (CEO) and Senior Vice President, Finance and Chief Financial Officer (CFO), on a timely basis so appropriate decisions can be made regarding public disclosure.

We have evaluated the effectiveness of the design and operation of our disclosure controls and procedures, under the supervision of our CEO and CFO. Based on this evaluation, we concluded the disclosure controls and procedures, as defined in National Instrument 52-109, were effective as of December 31, 2015.

### INTERNAL CONTROLS OVER FINANCIAL REPORTING

We are responsible for establishing and maintaining adequate internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. We assessed the design and effectiveness of internal controls over financial reporting as at December 31, 2015, and, based on that assessment, determined the design and operating effectiveness of internal controls over financial reporting was effective. However, because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements on a timely basis.

Effective July 1, 2015, we successfully implemented an Enterprise Resource Planning ("ERP") system and made changes to certain related processes. As a result of the ERP system, certain processes supporting our internal control over financial reporting changed in 2015.

Other than the ERP system implementation there have been no changes made to internal controls over financial reporting during the period ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting. Although the ERP implementation changed certain specific activities within the accounting function, it did not significantly affect the overall controls and procedures we follow in establishing internal controls over financial reporting.