Management's Discussion and Analysis of

VERESEN INC.

For the year ended December 31, 2014

March 12, 2015

TABLE OF CONTENTS

FINANCIAL AND OPERATING HIGHLIGHTS

($ Millions, except where noted)	**2014**	2013[1]	2012
Operating Highlights (100%)			
Pipeline			
Alliance – billion cubic feet per day	**1.556**	1.565	1.553
Ruby – billion cubic feet per day	**1.020**	n/a	n/a
AEGS – thousand barrels per day [2]	**289.1**	293.0	284.4
Midstream			
Hythe/Steeprock – million cubic feet per day [3]	**399.9**	412.9	393.1
Aux Sable – thousand barrels per day	**70.2**	70.4	72.2
Power – gigawatt hours (net)	**625.3**	561.5	925.9
Financial Results			
Equity and dividend income	**161.9**	163.3	143.3
Operating revenues	**302.1**	291.7	264.2
Adjusted net income attributable to Common Shares [4]	**30.7**	40.5	39.1
Per Common Share ($) – basic and diluted	**0.14**	0.21	0.20
Net income attributable to Common Shares	**52.4**	53.2	43.6
Per Common Share ($) – basic and diluted	**0.24**	0.27	0.22
Cash from operating activities	**214.6**	217.4	179.9
Distributable cash [4, 5]	**252.7**	228.9	211.4
Per Common Share ($) – basic and diluted	**1.12**	1.15	1.09
Dividends paid/payable [6]	**227.2**	199.7	193.5
Per Common Share ($)	**1.00**	1.00	1.00
Capital expenditures [7]	**147.8**	46.4	91.5
Financial Position			
Cash and short-term investments	**51.4**	25.2	16.1
Total assets	**4,737.5**	2,973.4	2,961.0
Senior debt	**1,811.4**	1,187.5	1,259.3
Subordinated convertible debentures	**-**	86.2	86.2
Shareholders' equity	**2,532.7**	1,305.7	1,231.0
Common Shares			
Outstanding – as at year end [8]	**285,029,036**	201,476,244	197,804,153
Average daily volume	**701,764**	302,801	378,758
Price per Common Share – close ($)	**18.36**	14.27	11.83

1. Certain comparative figures as at December 31, 2013 and for the year ended December 31, 2013 have been reclassified. See Note 5 in our December 31, 2014 consolidated financial statements.
2. Average daily volume for AEGS is based on toll volumes.
3. Average daily volume for Hythe/Steeprock is based on fee volumes.
4. 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.
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 $81.2 million of dividends satisfied through the issuance of Common Shares under our Premium Dividend™ (trademark of Canaccord Genuity Corp.) and Dividend Reinvestment Plan ("DRIP") for the year ended December 31, 2014 (2013 - $44.3 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 9, 2015, we had 287,109,612 Common Shares outstanding.

This MD&A, dated March 12, 2015, provides a review of the significant events and transactions that affected our performance during the year ended December 31, 2014 relative to December 31, 2013. It should be read in conjunction with our consolidated financial statements and notes as at and for the year ended December 31, 2014, prepared in accordance with accounting principles generally accepted in the United States ("US GAAP").

OVERALL FINANCIAL PERFORMANCE

Adjusted Net Income attributable to Common Shares

	Three months ended December 31		Year ended December 31	
($ Millions, except per Common Share amounts)	**2014**	2013	**2014**	2013
Adjusted net income before tax [(1)]				
Pipeline	**44.2**	27.3	**136.3**	107.4
Midstream	**21.2**	26.7	**81.7**	87.3
Power	**0.9**	(0.8)	**10.3**	(0.6)
Veresen - Corporate	**(43.1)**	(30.5)	**(160.5)**	(113.9)
Tax expense	**(10.6)**	(7.3)	**(20.8)**	(29.4)
Adjusted net income	**12.6**	15.4	**47.0**	50.8
Preferred Share dividends	**(4.0)**	(3.7)	**(16.3)**	(10.3)
Adjusted net income attributable to Common Shares	**8.6**	11.7	**30.7**	40.5
Per Common Share ($)	**0.03**	0.06	**0.14**	0.21

(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.

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, 2014, we generated adjusted net income attributable to Common Shares of $30.7 million or $0.14 per Common Share compared to $40.5 million or $0.21 per Common Share for 2013.

Our adjusted earnings reflect the progression of our strategy in 2014 as evidenced by the incremental pipeline earnings from the Ruby Pipeline acquisition and the benefits of diversification across our business lines. A key component of our strategy is the advancement of our Jordan Cove liquefied natural gas ("LNG") development project. This project requires funding through the development phase and these costs are expensed, impacting our earnings.

Adjusted earnings from our Pipeline and Power businesses increased year over year. Pipeline adjusted earnings include an incremental $15.6 million from our interest in the Ruby Pipeline, acquired on November 6, 2014. Both Alliance and AEGS also contributed higher adjusted earnings. Power adjusted results reflect increases across most of our facilities.

Midstream adjusted earnings, which include stable, predictable earnings generated from the Hythe/Steeprock take-or-pay contract, were down slightly as Aux Sable faced a challenging natural gas liquids ("NGL") market.

In March 2014, our proposed Jordan Cove LNG project received a conditional order from the U.S. Department of Energy ("DOE") to export LNG to countries that do not have a Free Trade Agreement with the United States. With the reduction in risk resulting from receipt of this conditional order, we dedicated additional resources towards our commercial, engineering, and financing work efforts.

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

Net Income attributable to Common Shares

	Three months ended December 31		Year ended December 31	
($ Millions, except per Common Share amounts)	**2014**	2013	**2014**	2013
Net income before tax				
Pipeline	**44.2**	27.3	**136.3**	107.4
Midstream	**21.2**	26.7	**81.7**	87.3
Power	**(2.9)**	1.2	**(2.0)**	13.2
Veresen - Corporate	**(9.3)**	(30.5)	**(121.8)**	(113.9)
Gain on sale of assets (impairment)	**(5.0)**	-	**9.3**	-
Tax expense	**(13.5)**	(7.8)	**(25.0)**	(32.9)
Net income from continuing operations	**34.7**	16.9	**78.5**	61.1
Net income (loss) from discontinued operations	**(9.7)**	(0.6)	**(9.8)**	2.4
Net income	**25.0**	16.3	**68.7**	63.5
Preferred Share dividends	**(4.0)**	(3.7)	**(16.3)**	(10.3)
Net income attributable to Common Shares	**21.0**	12.6	**52.4**	53.2
Per Common Share ($)				
Continuing operations	**0.12**	0.06	**0.28**	0.26
Discontinued operations	**(0.04)**	-	**(0.04)**	0.01
	0.08	0.06	**0.24**	0.27

For the year ended December 31, 2014, we generated net income attributable to Common Shares of $52.4 million or $0.24 per Common Share compared to $53.2 million or $0.27 per Common Share for 2013.

Our Power segment was impacted by the revaluation of the York Energy Centre interest rate hedge which resulted in a $26.1 million reduction in Power net income before tax for the year, and a $12.2 million pre-tax impairment loss on the three U.S. gas-fired assets sold January 8, 2015 included in the net loss from discontinued operations.

Corporate earnings include a $38.7 million pre-tax gain on forward foreign exchange contracts we entered into to manage the foreign exchange exposure relating to the Ruby acquisition.

During the first quarter of 2014 we sold the Culliton Creek run-of-river development project and our 50% interest in Alton Gas Storage, a proposed underground salt cavern facility, generating a combined pre-tax gain of $14.3 million. In the fourth quarter we recognized a $5.0 million impairment loss on land we hold in Ontario.

Fourth quarter earnings were impacted by the revaluation of the York Energy Centre interest rate hedge resulting in a $5.8 million reduction in earnings, by the recognition of a $33.8 million pre-tax gain relating to the forward foreign exchange contracts, and the $12.2 million pre-tax impairment loss on the three U.S. gas-fired assets sold January 8, 2015.

Distributable Cash [(1)]

	Three months ended December 31		Year ended December 31	
($ Millions, except per Common Share amounts)	**2014**	2013	**2014**	2013
Pipeline	**57.3**	40.7	**179.6**	157.0
Midstream	**33.8**	39.4	**130.6**	133.7
Power	**7.8**	5.3	**47.5**	34.4
Veresen – Corporate	**(17.7)**	(18.6)	**(65.6)**	(71.0)
Current tax	**(8.7)**	(7.3)	**(23.1)**	(14.9)
Preferred Share dividends	**(4.0)**	(3.7)	**(16.3)**	(10.3)
Distributable Cash [(1)]	**68.5**	55.8	**252.7**	228.9
Per Common Share ($)	**0.26**	0.28	**1.12**	1.15

(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, 2014, we generated distributable cash of $252.7 million, or $1.12 per Common Share, compared to $228.9 million or $1.15 per Common Share for 2013.

Strong cash flows generated by our pipeline and power businesses during the year were partially offset by higher cash taxes.

Alliance generated an additional $6.4 million of distributable cash compared to 2013, largely driven by the collection of higher depreciation rates, a full year's contribution from the Tioga lateral pipeline and the weakening of the Canadian dollar. Pipeline distributable cash also includes $15.6 million of distributions from Ruby, which we acquired in the fourth quarter of 2014.

Distributable cash from our Midstream segment decreased slightly from 2013 as an increase in distributable cash from Hythe/Steeprock was offset by a reduction in distributions from Aux Sable.

Distributable cash from our Power business increased as a result of higher distributions from York Energy Centre, benefiting from a one-time retroactive revenue settlement adjustment in the second quarter, and higher cash flows from our run-of-river hydro facilities.

Current tax was higher in the current year due primarily to higher U.S.-based taxable earnings from our Alliance pipeline business, reduced ability to carry back losses in 2014, and timing of utilization of foreign tax credits.

Higher Preferred Share dividends reflect the October 2013 issuance of Preferred Shares.

Corporate cash outflows decreased in 2014 relative to last year due primarily to lower interest costs driven by debt refinancing and repayment, and the conversion of our 5.75% Convertible Unsecured Subordinated Debentures, and by lower general and administrative costs.

Fourth quarter cash flows were impacted by the receipt of Ruby distributions and weaker fractionation margins at Aux Sable.

Cash from Operating Activities

	Three months ended December 31		Year ended December 31	
($ Millions)	**2014**	2013	**2014**	2013
Pipeline	**58.2**	41.3	**182.1**	158.1
Midstream	**46.8**	55.1	**137.7**	142.2
Power	**(2.1)**	14.2	**38.4**	43.7
Power - operating working capital from discontinued operations	**7.4**	7.2	**11.9**	14.9
Veresen - Corporate	**(39.1)**	(34.1)	**(155.5)**	(141.5)
	71.2	83.7	**214.6**	217.4

For the year ended December 31, 2014, we generated $214.6 million of cash from operating activities, compared to $217.4 million for the previous year. The year-over-year change in operating cash flows from our Pipeline and Midstream businesses generally reflect the same factors impacting distributable cash. The change in operating cash flows from our Power business reflect the same factors impacting distributable cash and changes in non-cash working capital. The change in Corporate cash flows reflect higher project development costs.

The quarter-over-quarter change in operating cash flows reflects the same factors discussed above for the year.

ACCOUNTING STANDARDS AND BASIS OF PRESENTATION

Our consolidated financial statements as at and for the year ended December 31, 2014 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 2014 consolidated financial statements. Additional information concerning our business is available on SEDAR at www.sedar.com or on our website at www.vereseninc.com.

In February 2014 the Alberta Securities Commission ("ASC") and Ontario Securities Commission ("OSC") issued a relief order which permits us to continue to prepare our financial statements in accordance with US GAAP until the earliest of: (i) January 1, 2019; (ii) the first day of the financial year that commences after we cease to have activities subject to rate regulation; or (iii) the effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within International Financial Reporting Standards specific to entities with activities subject to rate regulation. This ASC/OSC relief order effectively replaced and extended the previous relief order, which was due to expire effective January 1, 2015.

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 ability of Alliance to successfully realize its proposed new services framework and the timing thereof;*
- *the proposed Alliance toll rates effective December 1, 2015 and the impact on Alliance's future earnings;*
- *the ability of Alliance to recover asset retirement obligations through future tolls;*
- *Aux Sable's ability to realize upon the extraction agreements with producers and to attract volumes onto the Alliance pipeline;*
- *the extent of Aux Sable's exposure to commodity prices or basis differentials and its ability to mitigate such exposure;*
- *the 2015 pricing environment for ethane and propane;*
- *the timing of completion, and the cost, of the Channahon facility expansion;*
- *the impact of the Veresen Midstream transactions on our distributable cash, our sources of funding for Veresen Midstream and the timing of the closing of the Veresen Midstream transactions;*
- *the timing of the completion of construction and in-service dates of the St. Columban and Grand Valley Phase III wind projects;*
- *the timing of testing and projected in-service date of the Dasque-Middle run-of-river facility;*
- *the projected date for a final investment decision on Jordan Cove LNG and Pacific Connector Gas Pipeline;*
- *the projected date for commencing LNG production from Jordan Cove LNG;*
- *the impact our Jordan Cove LNG and Pacific Connector Gas Pipeline projects will have on the Ruby pipeline's long-term utilization;*
- *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

We are committed to providing competitive, reliable returns to our investors through a combination of dividends and increasing the value of our shares. Key elements of our strategy are:

Optimize our existing assets

- Drive productivity;
- Complete the Alliance re-contracting process to maximize value and leverage Alliance and Aux Sable's unique service offering while appropriately managing risk; and
- Expand Aux Sable's fractionation capacity at its Channahon Facility.

Grow where we have a strategic advantage

- Grow our Midstream business with a focus on our Hythe/Steeprock, Alliance and Aux Sable footprints;
- Grow our Pipeline business through expansions and extensions of the Alliance gathering systems, Ruby and AEGS and the development of our Pacific Connector Gas Pipeline project;
- Pursue a liquefied natural gas export business around our Jordan Cove project; and
- Grow our Power business with a primary focus on gas-fired generation development in western Canada and Ontario.

Maintain financial strength and flexibility

- Maintain a strong balance sheet and ample liquidity;
- Maintain a prudent capital structure that supports investment-grade credit ratings; and
- Underpin cash flows with long-term fee-for-service contracts.

Advancement of Strategy in 2014

In 2014, we made significant progress in the advancement of our strategy, as detailed below.

<u>Alliance Recontracting</u>

As of February 2015, Alliance has executed binding precedent agreements with numerous shippers securing over 95% of total targeted capacity post December 1, 2015, a combination of receipt and full path, for an average contract length of approximately five years. Alliance continues to negotiate with potential shippers for the remaining available capacity. The Alliance re-contracting process was approached in stages, in a strategically prioritized fashion. The first priority was to ensure the Aux Sable NGL fractionator in Channahon was filled by contracting with producers faced with options for managing their liquids-rich gas. This objective was exceeded in 2014, with sufficient capacity requests to support the approval of a 24,500 barrels per day expansion of the Channahon Facility. Having maximized the utilization of the Channahon Facility, the second priority has been to attract dry gas to fill the remaining capacity on the Alliance pipeline. This has been largely achieved, with remaining residual short-term capacity to be made available following regulatory approvals. Allance's new services offerings and recontracting activities are further discussed in the *Description of Business - Pipeline Business - Alliance Pipeline* section of this MD&A.

Ruby Acquisition

On November 6, 2014, we closed the acquisition of a 50% convertible preferred interest in the Ruby pipeline system for US $1.425 billion. Ruby is a newly-built 680-mile, 42-inch pipeline capable of transporting 1.5 bcf/d of natural gas. 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. The acquisition was funded with proceeds from a $920 million subscription receipt offering and from a new credit facility.

The Ruby acquisition provides us with an asset supported by high-quality, long-term take-or-pay contracts providing stable cash flows. Ruby enhances our portfolio of contracted pipeline assets providing diversification into a high-value market in the U.S. The convertible preferred interest structure provides us with downside risk protection, while preserving our ability to participate in significant future cash flow growth following additional contracting and/or de-leveraging. It provides us with US$91 million of preferred distributions annually, payable prior to any distributions to common shareholders, with any unpaid preferred distribution compounding at an annual return until paid. The preferred interest may be converted into common shares representing 50% of the outstanding common shares in the Ruby pipeline system at our option at any time, or automatically upon contracting of an incremental 250 mmcf/d of long-term firm capacity at rates generally consistent with current contracts.

We expect our Jordan Cove LNG project will support Ruby's continued and growing long-term utilization. The Ruby acquisition is further discussed in the *Description of Business - Pipeline Business - Ruby* section of this MD&A.

Formation of Veresen Midstream

On December 22, 2014 we announced the formation of a new entity, Veresen Midstream Limited Partnership ("Veresen Midstream"), which will be owned equally by us and affiliates of Kohlberg Kravis Roberts & Co. L.P. ("KKR"), a global investment firm. Veresen Midstream has entered into definitive agreements to acquire certain natural gas gathering and compression assets supporting Montney development in the Dawson area of northeastern British Columbia from Encana Corporation ("Encana") and the Cutbank Ridge Partnership ("CRP"). CRP is a partnership between Encana and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation. Veresen Midstream has also agreed to undertake up to $5 billion of new midstream expansion for Encana and CRP in the Montney region under a 30-year fee-for-service arrangement. Veresen Midstream will be our primary growth vehicle for our Canadian natural gas and NGL midstream business.

Veresen Midstream establishes us as a leading player in the core of the Montney, one of North America's most prolific and competitive resource plays. The partnership requires no up-front funding from us as it will be funded initially through committed non-recourse debt and a cash contribution from KKR, while we will fund 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. The Veresen Midstream transaction is further discussed in the *Description of Business - Midstream Business - Veresen Midstream* section of this MD&A.

Jordan Cove LNG Development Project

On March 24, 2014, we received a conditional order from the U.S. DOE to export LNG from our proposed Jordan Cove LNG export terminal to those countries that do not have a Free Trade Agreement with the United States. Under the DOE order, we are permitted to export natural gas to meet Jordan Cove's initial LNG capacity production of six million tonnes per annum. The DOE authorization is for a term of 20 years, commencing on the date of first export.

In the first quarter of 2014, we also received authorization from the National Energy Board in Canada to export natural gas from Canada to the U.S., and from the DOE to import natural gas from Canada into the U.S. to serve the proposed Jordan Cove LNG terminal.

In July 2014, Jordan Cove LNG and the associated Pacific Connector Gas Pipeline received their collective Notice of Schedule for environmental review from the FERC. Receipt of this schedule is an important milestone in the regulatory process. FERC's initial schedule called for a final Environment Impact Statement ("EIS") to be issued on February 27, 2015. On February 6, 2015 a revised Notice of Schedule was received from the FERC, indicating that the EIS will now be issued on June 12, 2015. Based on this revised schedule, we reviewed and updated the project timeline and expect to make a final investment decision in late-2015 or early-2016. With a four-year construction period, commercial LNG production is targeted for late-2019.

We have advanced the organizational structure of Jordan Cove LNG to ensure the appropriate resources are in place for the success of the project. Supporting this objective, in October 2014, we announced the appointment of Elizabeth (Betsy) Spomer as President and Chief Executive Officer of Jordan Cove LNG LLC and as an Executive Vice President of Veresen. Ms. Spomer brings over 30 years of experience in the energy industry, with the majority of her career in the LNG industry. We plan to continue to augment our LNG team, adding professionals who will be required through the construction and operating phases. Ms. Spomer and her team are based in Houston, Texas.

<u>Financing Strategy</u>

During 2014 we undertook a number of steps to strengthen our liquidity, reduce borrowing costs and reduce leverage. In April, we issued 17.3 million common shares at a price of $16.50 per share, providing gross proceeds of approximately $284.6 million. The Ruby acquisition was partially financed with a $920 million common equity offering, whereby we issued 56.1 million common shares at a price of $16.40 per share.

We refinanced $200 million of 5.6% senior notes which matured in July 2014 through the issuance of $200 million of 3.06% medium term notes maturing on June 13, 2019. In May 2014 we repaid the $50.4 million Clowhom term loan and in October we redeemed the remaining $51.7 million balance of the 5.75% Convertible Unsecured Subordinated Debentures.

As a result of the above activities, we reduced our debt to total capitalization ratio from 46% to 42% over the course of the year.

In June 2014, the term of the Revolving Credit Facility was extended such that it now matures on May 31, 2018.

DESCRIPTION OF BUSINESS

Pipeline Business

Our Pipeline business represented 50% of our total asset base as at December 31, 2014 and is comprised of:

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

Each of Alliance, Ruby, and AEGS are stable cash flow generators that are supported by take-or-pay transportation agreements.

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 1.325 billion cubic feet per day of liquids-rich natural gas on a firm-service basis. 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 receipt capacity of over 6 billion cubic feet per day. 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 has firm-service transportation service contracts with primary terms extending to December 1, 2015 with a group of 30 shippers. Under the transportation service contracts, each shipper is obligated to pay monthly demand charges based on their contracted firm volume, regardless of volumes actually transported. These transportation contracts provide toll revenues sufficient to recover the costs of providing transportation service to shippers, including depreciation, debt financing costs and an allowed return on equity.

During 2014, Alliance placed into service several new receipt interconnection facilities that increased the pipeline's receipt capacity by up to 470 mmcf/d from developing liquids-rich sources of natural gas in northeastern British Columbia and northwestern Alberta. The cost to provide these receipt facilities is funded by the requesting customer. A number of additional receipt interconnection facilities are in the planning and design stage.

2015 Tolls

Alliance made its 2015 Canadian toll filing to the National Energy Board on October 31, 2014, and its 2015 U.S. rate filing with the FERC on November 28, 2014. Effective January 1, 2015, the firm transportation toll will increase from $0.96/mcf in 2014 to $1.00/mcf on Alliance Canada, but decrease from US$0.60/mcf to US$0.58/mcf on Alliance U.S.

Proposed New Services Offerings

Subject to regulatory approval, Alliance is offering capacity for transportation commencing December 1, 2015, under a proposed new services framework. The new services framework, which includes both fixed and flexible tolling options, responds to current market requirements and the diverse needs of existing and prospective shippers. The new services offerings include both full-path and segmented services with a new Canadian trading pool and a revised hydrocarbon dewpoint specification, which will facilitate the transportation of higher heat content natural gas. The services offer shippers competitive fixed tolls for medium and long-term services and biddable tolls for interruptible and seasonal service.

On May 22, 2014, Alliance Canada filed an application with the NEB for regulatory approval of the Canadian tolls and tariff provisions Alliance needs to implement its new services offering effective December 1, 2015. Similarly, Alliance U.S. will be applying to the FERC in 2015 for regulatory approval of its U.S. services and rates. On August 20, 2014, the NEB issued a Hearing Order establishing a written proceeding for the review of Alliance Canada's new services offerings application. The hearing concludes with oral final argument scheduled to start April 15, 2015. A decision by the NEB is expected mid-year 2015.

Alliance has executed binding precedent agreements with numerous shippers securing over 95% of total targeted capacity, a combination of receipt and full path, for an average contract length of approximately five years.

While contract work with shippers continues under the new services framework and the NEB approval process is in progress, we anticipate firm service tolls to transport gas from the Alberta and B.C. receipt zones to the pipeline terminus near Chicago commencing December 1, 2015 will be lower than current toll rates. Canadian tolls for firm contracts with three- and four-year terms are proposed to be $0.67/mcf and $0.84/mcf from the Alberta and B.C. receipt zones, respectively, to the U.S. border, while rates on Alliance U.S. are proposed to be US$0.42/mcf. We expect the decrease in future toll revenues to be partially mitigated by new transportation services revenues. Alliance has historically made approximately 20% of its 1.325 bcf/d firm capacity available shippers at no incremental cost as Authorized Overrun Service, or “AOS”. Under the new services framework, AOS will no longer be offered and this non-firm capacity will be sold as an interruptible service. We are investigating other opportunities to generate additional revenue from the new services offerings.

NEB Abandonment Funding Initiative

Alliance is responsible for compliance with all laws and regulations concerning the abandonment of the pipeline and related facilities at the end of their respective lives.

Following a public hearing in early 2009, the NEB directed all federally-regulated pipeline companies, including Alliance, to start collecting and setting aside funds to cover future abandonment costs. In accordance with the mandated framework and action plan, collection of the funds will commence in 2015.

On May 6, 2014, the NEB approved Alliance's filed pipeline abandonment cost estimate. On May 29, 2014, the NEB approved Alliance's proposed trust approach, as well as its proposed collection methodology. In accordance with these decisions, Alliance filed its detailed Trust Agreement for the NEB's approval on September 2, 2014. Alliance's statement of Investment Policies and Procedures applicable to its Pipeline Abandonment Trust was filed with the NEB on December 1, 2014.

On December 4, 2014, Alliance filed for approval with the NEB its Annual Contribution Amount, Pipeline Abandonment Demand Surcharge of $0.023/mcf, and revised tariff sheets to take effect January 1, 2015. On December 18, 2014, the NEB approved Alliance's filing on an interim basis. On March 10, 2015, the NEB approved Alliance's filing on a final basis.

Ruby Pipeline

On November 6, 2014, we closed the acquisition of a 50% convertible preferred interest in the Ruby pipeline system for US $1.425 billion. The acquisition was made through a wholly-owned subsidiary of Veresen. Ruby is a newly-built, 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.

The acquisition was funded with proceeds from a $920 million subscription receipt offering and from a new credit facility (details of the financing is discussed in the *Liquidity and Capital Resources* section of this MD&A).

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 nine 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, 2014, our Midstream business represented 26% of total assets.

Hythe/Steeprock

The Hythe/Steeprock complex is located in the Cutbank Ridge region of northwest Alberta and northeast British Columbia. Natural gas and NGLs in the region are produced from the prolific Montney, Cadomin and other geological formations. The Hythe/Steeprock complex is comprised of two natural gas processing plants with combined functional capacity of 516 mmcf/d, as well as approximately 40,000 horsepower of compression and 370 km of gas gathering lines. The Hythe plant processes both sour and sweet natural gas, while the Steeprock plant is a sour gas processing facility.

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, a major natural gas producer. 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. Actual monthly volumes delivered by Encana can and do vary relative to the minimum volume commitments set out in the Hythe/Steeprock MSA. The Hythe/Steeprock MSA provides a mechanism whereby limited excess or deficiency volumes can be carried forward for a rolling 12-month period and credited towards any changes resulting from deliveries in deficiency or excess for the minimum volume commitment.

Veresen Midstream

We will fund our interest in Veresen Midstream by contributing our Hythe/Steeprock gathering and processing assets valued at $920 million, and in exchange will receive from Veresen Midstream $420 million in cash, resulting in a 50% equity position valued at $500 million. KKR will fund its 50% interest in Veresen Midstream by contributing $500 million in cash. Concurrently, Veresen Midstream will acquire gathering and compression infrastructure and ongoing construction projects from Encana and CRP in the Dawson region of the Montney in British Columbia for total cash consideration of approximately $600 million, plus actual costs accrued in 2015. This infrastructure is located adjacent to the Hythe/Steeprock assets.

In addition to cash on hand, acquisition of this infrastructure will also be funded from new Veresen Midstream credit facilities, which will be non-recourse to Veresen.

Veresen Midstream and CRP will enter into a 30-year, fee-for-service midstream services agreement (the "Dawson MSA") with respect to the newly acquired infrastructure and future infrastructure, referred to as the "Dawson Assets", to be constructed within an area of mutual interest ("AMI"). We will provide day-to-day management of Veresen Midstream. The Hythe/Steeprock MSA remains unchanged, with Veresen Midstream operating the Hythe and Steeprock plants.

Veresen Midstream will commit to fund up to $5 billion of new infrastructure within the AMI to service CRP's planned production growth, including gas gathering pipelines, compression and processing facilities. Veresen Midstream's commitment to investments in compression and processing facilities is limited to projects that commence within the next six years. All new infrastructure investment is underpinned by the Dawson MSA which provides for strong expected returns on capital, a production dedication within the AMI and financial protections.

In the near term, plans include the construction of the 400 mmcf/d Sunrise gas plant and the 200 mmcf/d Tower gas plant, both greenfield sweet gas compression and processing plants with NGL recovery, along with associated incremental gathering pipelines. Construction of the Sunrise and Tower plants is scheduled to begin in 2015, with in-service dates anticipated in 2017. Future infrastructure may include additional gas gathering pipelines, compression and processing facilities to meet CRP's planned volume growth.

We have formed Veresen Midstream with KKR to complete these transactions and to pursue additional growth opportunities in Canadian natural gas and NGL midstream. All of our and half of KKR's Veresen Midstream equity will be held in partnership units that are eligible to receive cash distributions. The remaining half of KKR's initial equity investment will be 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 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 is expected to be neutral to our distributable cash in 2015 and 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%.

Veresen Midstream expects to fund approximately 55% to 60% of its growth program with debt and the remainder with future equity contributions from KKR and us. All future equity requirements for Veresen Midstream will be funded by the partners in cash-paying units on a pro-rata basis.

These transactions are expected to close late in the first or early in the second quarter of 2015 and are subject to normal closing conditions, including receipt of approvals under the Competition Act and the Investment Canada Act.

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 50% interest in the Septimus Gas Plant, a natural gas processing plant, with a processing capacity of 75 mmcf/d, 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;
- 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; and
- Sable NGL Services (50% ownership), which, from time to time, holds short-term firm natural gas transportation capacity on the Alliance pipeline.

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, as well as growth and maintenance capital expenditures related to the Channahon Facility, subject to certain limits in the case of capitalized costs.

In July 2011, Aux Sable acquired the Palermo Conditioning Plant and the Prairie Rose Pipeline in the Bakken. Aux Sable earns processing and pipeline transportation fees from these assets, 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 have focused on working with producers who are developing liquids-rich fields in the Montney and Duvernay which are not yet connected to the Alliance Pipeline system. Aux Sable has 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, have 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) and is expected to be completed in mid-2016.

Power Business

We have grown our Power business through greenfield development and acquisitions into a diverse portfolio of power generation facilities capable of generating in excess of 780 MW. A significant portion of our power facilities are 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 14% of our total asset base as determined at December 31, 2014 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 and II in Ontario (9 MW and 11 MW, respectively; 75% ownership);
  - St. Columban in Ontario, currently under construction (33 MW; 90% ownership);
  - Grand Valley phase III in Ontario, currently under construction (40 MW);

- Assets held for sale (sold January 8, 2015)
  - Brush II power generation facility in Colorado (70 MW);
  - Ripon and San Gabriel cogeneration facilities in California (49 MW and 44 MW, respectively).

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$27.4 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.

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.

Construction of the Dasque-Middle run-of-river hydro facility, a 20-MW project located in northwest British Columbia, was completed on December 18, 2014. As required by BC Hydro, the facility will be placed into commercial service when it has successfully completed a 72-hour performance and reliability test. Due to freezing winter temperatures in December, the water flow rate was not high enough to complete this test. We expect to complete testing later in the spring of 2015 when adequate water flows resume.

Wind Power Facilities

We hold a 75% ownership interest in the two operational phases of the Ontario-based Grand Valley wind project, which sells its output to the Ontario Power Authority (OPA) under long-term contracts.

Construction of the St. Columban wind project (33 MW; 90% interest) commenced during the first quarter of 2014 with completion and an in-service date expected in the first half of 2015.

The proposed Grand Valley Phase III wind project (40 MW; 75% interest) received its Renewable Energy Approval from the Ontario Minister of Environment and Climate Change on October 15, 2014. We commenced construction of this wind project in the fourth quarter of 2014, with completion and an in-service date expected in late 2015.

RESULTS OF OPERATIONS – BY BUSINESS SEGMENT

Pipeline Business

			Three months ended December 31, 2014				Three months ended December 31, 2013	
($ Millions, except where noted)	**Total**	Alliance	Ruby [3]	AEGS	Total	Alliance	Ruby	AEGS
Equity income	**26.3**	26.3	-	-	24.8	24.8	-	-
Dividend income	**15.6**	-	15.6	-	-	-	-	-
Earnings before interest, tax depreciation and amortization (“EBITDA”) [(1)]	**6.9**	-	-	6.9	7.2	-	-	7.2
Depreciation and amortization	**(3.5)**	-	-	(3.5)	(3.4)	-	-	(3.4)
Interest and other finance	**(1.1)**	-	-	(1.1)	(1.3)	-	-	(1.3)
Net income before tax	**44.2**	26.3	15.6	2.3	27.3	24.8	-	2.5
Distributable cash	**57.3**	36.8	15.6	4.9	40.7	35.6	-	5.1
Volumes (100%)		**1.547**	**0.845**	**296.8**		1.552	-	301.0
		bcf/d	**bcf/d**	**mbbls/d** [(2)]		bcf/d	bcf/d	mbbls/d [(2)]

			Year ended December 31, 2014				Year ended December 31, 2013	
($ Millions, except where noted)	**Total**	Alliance	Ruby [3]	AEGS	Total	Alliance	Ruby	AEGS
Equity income	**112.1**	112.1	-	-	99.6	99.6	-	-
Dividend income	**15.6**	-	15.6	-	-	-	-	-
EBITDA	**27.4**	-	-	27.4	26.8	-	-	26.8
Depreciation and amortization	**(14.0)**	-	-	(14.0)	(13.9)	-	-	(13.9)
Interest and other finance	**(4.8)**	-	-	(4.8)	(5.1)	-	-	(5.1)
Net income before tax	**136.3**	112.1	15.6	8.6	107.4	99.6	-	7.8
Distributable cash	**179.6**	144.8	15.6	19.2	157.0	138.4	-	18.6
Volumes (100%)		**1.556**	**1.020**	**289.1**		1.565	-	293.0
		bcf/d	**bcf/d**	**mbbls/d** [(2)]		bcf/d	bcf/d	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 Ruby on November 6, 2014 and, as such, dividend income reflects amounts earned from November 6 to December 31, 2014

Alliance

Operational Highlights

Transportation deliveries for the year ended December 31, 2014 averaged 1.556 bcf/d, compared to 1.565 bcf/d for the same period last year.

Financial Highlights

Distributable cash for the year ended December 31, 2014 was $144.8 million, compared to $138.4 million for the previous year. The increase reflects higher revenues due to an increase in negotiated depreciation rates, a full year's contribution from the Tioga lateral, which went into service September 2013, and the weakening of the Canadian dollar throughout 2014, partially offset by lower returns as a result of a declining investment base.

Net income before tax for the year ended December 31, 2014 was $112.1 million, compared to $99.6 million for the previous year, reflecting the same factors impacting distributable cash.

Fourth quarter distributable cash and net income before tax reflect the same underlying factors as for the full year.

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 approximately nine years. Transportation deliveries for the year averaged 1.020 bcf/d.

Financial Highlights
Distributable cash and net income for the year ended December 31, 2014 was $15.6 million, representing our share of the US$91.0 million annual distributions paid to the holders of the convertible preferred shares from the date of acquisition.

AEGS

Operational Highlights
Toll volumes for the year ended December 31, 2014 averaged 289.1 mbbls/d compared to 293.0 mbbls/d for the previous year due to an unplanned outage by a major petrochemical plant served by AEGS in the third quarter resulting in lower ethane deliveries.

Toll volumes for the fourth quarter were 296.8 mbbls/d compared to 301.0 mbbls/d for the same period last year, reflecting slightly weaker ethane demand.

Financial Highlights
For the year ended December 31, 2014, AEGS generated $19.2 million in distributable cash and $8.6 million in net income before tax, compared to $18.6 million in distributable cash and $7.8 million in net income before tax for the previous year. Results for the current year and the fourth quarter were consistent with the same periods last year.

Midstream Business

		Three months ended December 31, 2014			Three months ended December 31, 2013	
($ Millions, except where noted)	**Total**	Hythe/ Steeprock	Aux Sable	Total	Hythe/ Steeprock	Aux Sable
Equity income	**12.9**	-	12.9	17.5	-	17.5
EBITDA	**18.3**	18.3	-	19.0	19.0	-
Depreciation and amortization	**(10.0)**	(10.0)	-	(9.8)	(9.8)	-
Net income before tax	**21.2**	8.3	12.9	26.7	9.2	17.5
Distributable cash	**33.8**	17.3	16.5	39.4	17.5	21.9
Volumes (100%)						
Fee Volumes[1]		**400.8**			410.5	
		mmcf/d			mmcf/d	
Ethane			**21.0**			39.4
Propane plus			**46.7**			48.8
			67.7			88.2
			mbbls/d			mbbls/d

		Year ended December 31, 2014			Year ended December 31, 2013	
($ Millions, except where noted)	**Total**	Hythe/ Steeprock	Aux Sable	Total	Hythe/ Steeprock	Aux Sable
Equity income	**48.2**	-	48.2	52.3	-	52.3
EBITDA	**73.2**	73.2	-	74.3	74.3	-
Depreciation and amortization	**(39.7)**	(39.7)	-	(39.3)	(39.3)	-
Net income before tax	**81.7**	33.5	48.2	87.3	35.0	52.3
Distributable cash	**130.6**	73.6	57.0	133.7	72.6	61.1
Volumes (100%)						
Fee Volumes(1)		**399.9**			412.9	
		mmcf/d			mmcf/d	
Ethane			**22.6**			25.1
Propane plus			**47.6**			45.3
			70.2			70.4
			mbbls/d			mbbls/d

(1) 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.

Hythe/Steeprock

Operational Highlights

For the year ended December 31, 2014, fee volumes at Hythe/Steeprock averaged 399.9 mmcf/d which is comprised of the minimum volume commitment under the Hythe/Steeprock MSA and natural gas from third party producers. Fee volumes decreased three percent compared to last year as a result of downstream pipeline pressure restrictions impacting our Hythe plant. The variance further reflects higher volumes processed in 2013 subsequent to the May 2013 Hythe turnaround.

As part of our ongoing commitment to asset integrity and reliability, we successfully completed the Steeprock facility turnaround in the month of June 2014. The turnaround was completed ahead of schedule and on budget. The minimum volume commitment under the Hythe/Steeprock MSA remained applicable during the turnaround period. A turnaround of this scale for the Steeprock facility is currently planned to be completed every three years.

During 2014, the Hythe and Steeprock facilities both operated at reliability factors greater than 99%, exceeding the target factor under the Hythe/Steeprock MSA.

Fee volumes and reliability factors in the fourth quarter were consistent with the year.

Financial Highlights

For the year ended December 31, 2014, distributable cash for Hythe/Steeprock was $73.6 million compared to $72.6 million for the previous year. The increase was due to higher revenues attributed to the recovery of maintenance capital expenditures from Encana and the annual fee escalation as per the Hythe/Steeprock MSA.

Net income before tax for the year ended December 31, 2014 decreased by $1.5 million to $33.5 million reflecting lower third party revenue and net volume deficiencies in the current year. Downstream pipeline pressure restrictions impacted the Hythe plant's ability to process natural gas and the Steeprock plant turnaround in mid-2014, resulting in the deferred recognition of a portion of take-or-pay revenues during this period.

Net income before tax for the fourth quarter of 2014 decreased compared to the fourth quarter of the previous year reflecting the same factors impacting the year.

Aux Sable

NGL Market Overview

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Average USGC ethane margin (US$/gallon)	**(0.05)**	0.02	**(0.02)**	0.02
Average USGC propane plus margin (US$/gallon)	**0.52**	0.96	**0.75**	0.84
Average USGC propane (US$/gallon)	**0.77**	1.20	**1.04**	1.00
Average Henry Hub natural gas (US$/mmbtu)	**3.75**	3.84	**4.34**	3.72
Average Chicago Citygate natural gas (US$/mmbtu)	**3.90**	4.03	**5.57**	3.85
Average WTI crude oil (US$/bbl)	**73.24**	97.64	**93.02**	98.03
Average Chicago - AECO differential ($/mmbtu)	**0.88**	0.72	**1.61**	0.80

U.S. Gulf Coast ethane margins remained weak throughout 2014 primarily due to continued oversupply, and were negative in the fourth quarter as competing feedstocks for ethylene production, such as propane and butane, became more competitive due to respective pricing declines.

USGC propane plus margins were stronger in the first half of 2014 relative to the same period last year due to a stronger pricing environment, although margins realized by Aux Sable were less favourable due to higher make-up gas costs in Chicago. USGC propane plus margins weakened in the second half of 2014 relative to the same period last year, particularly in the fourth quarter, as propane plus prices followed the downward trend set by crude oil.

Seasonal demand factors such as winter heating and crop drying fell short of market expectations and were insufficient to work down elevated U.S. propane inventories. Propane stocks in the U.S. remained above the five-year range during the fourth quarter of 2014, ending at 74 million barrels. This represents a 31 million barrel increase over the ending balance for 2013, or a 74% year-over-year increase. USGC propane prices averaged US$0.77 per gallon in the fourth quarter of 2014 with December's average coming in at US$0.55, a reflection of both elevated U.S. inventories and pressure on natural gas liquids prices stemming from the decline in crude oil prices.

Following the volatile natural gas price environment in the first quarter created by extremely cold temperatures in the U.S. Mid-West, natural gas prices moderated throughout the remainder of the year. The Chicago Citygate gas price averaged US$3.90 per mmbtu in the fourth quarter, down from US$4.03 per mmbtu in the fourth quarter of 2013.

Operational Highlights

	Three months ended December 31		Year ended December 31	
	2014	2013	**2014**	2013
Average volume receipts				
Prairie Rose Pipeline (mmcf/d)	**101.1**	102.1	**98.3**	103.9
Average sales at Channahon				
Ethane (mbbls/d)	**21.0**	39.4	**22.6**	25.1
Propane plus (mbbls/d)	**46.7**	48.8	**47.6**	45.3
Total NGLs (mbbls/d)	**67.7**	88.2	**70.2**	70.4

During the year ended December 31, 2014, Aux Sable processed 96% of the natural gas delivered by Alliance compared to 98% last year. The decrease is attributable to reduced processing due to uneconomic margins, bypassing volumes to alleviate high inventories, and downtime for planned maintenance.

Receipts into the Prairie Rose Pipeline in North Dakota averaged 98 mmcf/d during the year ended December 31, 2014 compared to 104 mmcf/d for the previous year primarily due to the movement of volumes from the Prairie Rose Pipeline to delivery on the new Tioga Lateral which commenced operation in the third quarter of 2014.

The average heat content of the natural gas delivered to the Alliance interconnection at Bantry, North Dakota was approximately 1,359 btu/ft^3 for the year ended December 31, 2014 compared to 1,379 btu/ft^3 for the previous year. The heat content declined slightly due to the movement of volumes to the Tioga Lateral. The heat content of the liquids-rich natural gas stream being delivered out of the Bakken continues to be very high. In comparison, the heat content including western Canada natural gas delivered on the Alliance system during the year averaged 1,127 btu/ft^3 compared to 1,112 btu/ft^3 in 2013.

Aux Sable sold 70 mbbls/d of NGLs during each of the years ended December 31, 2014 and 2013. Average ethane volumes sold decreased to 23 mbbls/d for the year ended December 31, 2014 from 25 mbbls/d for the previous year as uneconomic margins drove higher ethane reinjection, which also resulted in the fourth quarter decrease relative to the same period last year.

Propane plus sales volumes were 47 mbbls/d for the year ended December 31, 2014 compared to 45 mbbls/d for the previous year. The increase can be attributed to higher contracted volumes due to the success Aux Sable has been able to achieve through their Rich Gas Premium initiatives, and increased heat content from those volumes as producers target liquids-rich production. The fourth quarter decrease relative to the same period last year was due to bypass and reinjection in 2014, as the margins for propane were uneconomic for a portion of December.

Financial Highlights

Components of Aux Sable Equity Income:

	Three months ended December 31		Year ended December 31	
(Veresen's share; $ Millions)	**2014**	2013	**2014**	2013
Margin-based lease revenues				
Amount generated during period	**5.2**	12.5	**23.4**	39.2
Margin recognized from prior period	**3.3**	1.8	**-**	-
(Unrecognized margin generated in period)	**-**	-	**-**	-
Amount recognized as revenue	**8.5**	14.3	**23.4**	39.2
Pipeline capacity margin	**0.3**	(2.4)	**5.8**	(10.6)
Other margin based activities	**4.5**	4.8	**16.2**	17.2
Fixed fee activities	**8.6**	10.2	**35.4**	38.8
General, administrative, operating, and maintenance	**(5.8)**	(6.8)	**(20.9)**	(22.4)
Depreciation and amortization	**(3.1)**	(2.6)	**(11.2)**	(10.2)
Interest and other finance	**(0.1)**	-	**(0.5)**	0.3
Net income before tax / equity income	**12.9**	17.5	**48.2**	52.3

For the year ended December 31, 2014 Aux Sable generated $57.0 million of distributable cash and $48.2 million of net income before tax, compared to $61.1 million and $52.3 million in 2013.

Margin-based lease revenues decreased in 2014 primarily due to lower fractionation margins driven by higher make-up gas prices throughout most of the year and the steep decline in propane plus prices in the fourth quarter mirroring the decline of global crude oil prices, partially offset by the effects of a weaker Canadian dollar in 2014.

Pipeline capacity margins, related to the purchase and sale of natural gas by certain Aux Sable entities utilizing Alliance pipeline capacity, were higher in 2014, largely driven by the extreme cold winter weather in the U.S. Mid-West during the first quarter and unfavourable market dynamics in western Canada relative to Chicago in the fourth quarter.

Fixed fee activities decreased relative to 2013 due to lower volumes flowing through Aux Sable's Palermo Conditioning Plant as a result of the Hess Tioga Plant commencing service in May 2014.

Fourth quarter distributable cash and net income decreased compared to the same period last year due to the same underlying factors as discussed above.

Power Business

				Three months ended December 31, 2014				Three months ended December 31, 2013
($ Millions, except where noted)	**Total**	Gas-Fired/ District Energy	Renewables	Power-Corporate	Total	Gas-Fired/ District Energy	Renewables	Power-Corporate
Gain (loss) on interest rate hedge	**(3.8)**	(3.8)	-	-	2.0	2.0	-	-
Other equity income	**1.5**	0.9	0.6	-	1.3	0.5	0.8	-
Equity Income	**(2.3)**	(2.9)	0.6	-	3.3	2.5	0.8	-
EBITDA	**9.3**	7.0	4.7	(2.4)	8.3	7.9	2.3	(1.9)
Depreciation and amortization	**(6.7)**	(4.4)	(2.3)	-	(6.8)	(4.4)	(2.4)	-
Interest and other finance	**(3.0)**	(2.4)	(0.6)	-	(3.6)	(2.6)	(1.0)	-
Foreign exchange and other	**(0.2)**	(0.1)	-	(0.1)	-	-	-	-
Net income (loss) before tax	**(2.9)**	(2.8)	2.4	(2.5)	1.2	3.4	(0.3)	(1.9)
Distributable cash	**7.8**	5.5	4.8	(2.5)	5.3	5.9	1.9	(2.5)
Volumes (GWh)								
Gross	**168.7**	14.2	154.5	-	152.9	26.8	126.1	-
Net	**138.1**	8.9	129.2	-	124.4	22.0	102.4	-
				Year ended December 31, 2014				Year ended December 31, 2013
($ Millions, except where noted)	**Total**	Gas-Fired/ District Energy	Renewables	Power-Corporate	Total	Gas-Fired/ District Energy	Renewables	Power-Corporate
Gain (loss) on interest rate hedge	**(12.3)**	(12.3)	-	-	13.8	13.8	-	-
Other equity income	**10.0**	7.5	2.5	-	4.5	2.3	2.2	-
Equity Income	**(2.3)**	(4.8)	2.5	-	18.3	16.1	2.2	-
EBITDA	**40.0**	32.4	16.4	(8.8)	36.2	31.4	13.2	(8.4)
Depreciation and amortization	**(27.2)**	(17.9)	(9.3)	-	(26.9)	(17.5)	(9.1)	(0.3)
Interest and other finance	**(12.6)**	(9.3)	(3.3)	-	(14.4)	(10.0)	(4.4)	-
Foreign exchange and other	**0.1**	-	-	0.1	-	-	-	-
Net income (loss) before tax	**(2.0)**	0.4	6.3	(8.7)	13.2	20.0	1.9	(8.7)
Distributable cash	**47.5**	38.6	17.4	(8.5)	34.4	33.9	9.4	(8.9)
Volumes (GWh)								
Gross	**753.1**	205.4	547.7	-	681.4	164.2	517.2	-
Net	**625.3**	168.3	457.0	-	561.5	129.3	432.2	-

Operational Highlights

For the year ended December 31, 2014, our power facilities operated in line with our expectations, providing consistent operating earnings compared to the previous year. Our facilities benefited from the high price environment in early 2014 driven by the extreme cold winter weather throughout eastern Canada and northeastern parts of the United States, as well the high water flows in parts of British Columbia during the fourth quarter.

Financial Highlights

For the year ended December 31, 2014, distributable cash was $47.5 million, a $13.1 million increase compared to the previous year.

Our renewable energy facilities generated an $8.0 million increase in cash flows during the year compared to 2013, largely due to higher water flows at our BC run-of-river facilities and robust first quarter energy prices in the market served by Glen Park driven by the extreme cold winter weather.

Our gas-fired and district energy systems contributed $4.7 million of additional distributable cash in 2014 compared to the previous year, largely due to higher distributions from the York Energy Centre. In addition to its strong operating performance, York Energy Centre results reflect a retroactive adjustment received in relation to its power purchase agreement with the OPA. The amendment to the contract was made to address current Independent Electricity System Operator market rules that were not contemplated in the original contract. The original contract payment mechanism resulted in a misalignment between contract capacity and actual power generation. The amended contract capacity payment mechanism corrects this misalignment. The retroactive adjustment was applied to the period from commencement of operations in May 2012 to April 2014, and our share amounted to $3.9 million.

For the year ended December 31, 2014, net loss before tax from our Power business was $2.0 million, a $15.2 million decrease compared to the previous year. The revaluation of the York interest rate hedge resulted in a $26.1 million reduction in net income before taxes compared to 2013.

Fourth quarter distributable cash increased in the current year relative to the same period last year due to higher water flows at our BC run-of-river facilities. Our gas-fired and district energy facilities reflected strong operational performance, providing fourth quarter results consistent with the same period last year. The decrease in fourth quarter net income before tax relative to the same period last year primarily reflects the revaluation of the York interest rate hedge.

Veresen-Corporate

	Three months ended December 31		Year ended December 31	
($ Millions)	**2014**	2013	**2014**	2013
Equity loss	**3.7**	2.5	**11.7**	6.9
General and administrative	**6.9**	8.9	**28.7**	30.9
Project development	**20.0**	9.6	**78.8**	33.5
Depreciation and amortization	**0.5**	0.7	**2.4**	2.3
Interest and other finance	**13.3**	10.2	**41.3**	42.4
Foreign exchange and other	**(35.1)**	(1.4)	**(41.1)**	(2.1)
Net expenses before tax	**9.3**	30.5	**121.8**	113.9
Distributable Cash	**(17.7)**	(18.6)	**(65.6)**	(71.0)

For the year ended December 31, 2014, we incurred $121.8 million of net corporate expenses before taxes, a $7.9 million increase compared to the previous year. The increase was due to higher project development spending related to our Jordan Cove LNG and Pacific Connector Gas Pipeline projects, partially offset by a $38.7 million pre-tax gain on forward foreign exchange contracts entered into to manage the foreign exchange exposure relating to the Ruby acquisition.

Interest costs during the year were lower due to the repayment of debt using cash proceeds from our April 2014 equity offering, the refinancing of our $200 million 5.6% senior notes which matured in July 2014 through the issuance of $200 million 3.06% senior notes and the October 2014 redemption of the remaining balance of the 5.75% Convertible Unsecured Subordinated Debentures. Fourth quarter interest costs were higher due to the new credit facility drawn to fund the Ruby acquisition.

Taxes

($ Millions)	Three months ended December 31 2014	2013 [1]	Year ended December 31 2014	2013 [1]
Net income from continuing operations before tax	**48.2**	24.7	**103.5**	94.0
Current tax	**(10.4)**	(8.8)	**(29.6)**	(19.0)
Deferred tax	**(3.1)**	1.0	**4.6**	(13.9)
Total tax	**(13.5)**	(7.8)	**(25.0)**	(32.9)
Effective rate	**28.0%**	31.6%	**24.2%**	35.0%

(1) Certain comparative figures for the year ended December 31, 2013 have been reclassified. See Note 5 in our December 31, 2014 consolidated financial statements.

Our effective tax rate for 2014 decreased compared to 2013 due to a lower proportion of U.S. earnings, which are subject to a higher tax rate relative to Canadian earnings. In addition, the gains on sale of assets and forward foreign exchange contracts are subject to the lower Canadian capital gains tax rate.

LIQUIDITY AND CAPITAL RESOURCES

($ Millions, except where noted)	Year ended December 31 2014		2013	
Cash flows				
Operating activities	**214.6**		217.4	
Investing activities	**(1,794.2)**		(120.6)	
Financing activities	**1,606.3**		(87.3)	
Cash and short-term investments	**51.4**		25.2	
Capitalization				
Senior debt (1)	**1,811.4**	**42%**	1,187.5	46%
Subordinated convertible debentures	**-**	**-%**	86.2	3%
Shareholders' equity	**2,532.7**	**58%**	1,305.7	51%
	4,344.1	**100%**	2,579.4	100%

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

During the year we undertook a number of initiatives to strengthen our liquidity, reduce borrowing costs and reduce leverage. As discussed below under *Equity Financing Activities* and *Debt Financing Activities*, we issued common equity in April and November, refinanced at a lower interest rate senior notes that were set to mature in July 2014, repaid the Clowhom term loan and redeemed the remaining balance of our 5.75% Convertible Unsecured Subordinated Debentures. As a result of these activities, we reduced our debt to total capitalization ratio from 46% to 42% over the course of the year.

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, 2014, we had $595 million of committed credit facilities of which $150.6 million was drawn, including $29.0 million in letters of credit.

At December 31, 2014, we had cash and short-term investments of $51.4 million (December 31, 2013 - $25.2 million) and non-cash working capital of $37.7 million (December 31, 2013 - $43.6 million).

Investing Activities
For the year ended December 31, 2014, we used $1,794.2 million of cash to fund our investing activities, compared to $120.6 million in 2013. Significant investing activities for the years ended December 31, 2014 and 2013 are presented in the table below.

	Year ended December 31	
($ Millions)	**2014**	2013
Acquisitions and dispositions		
Ruby acquisition, net of gains on forward foreign exchange contracts	**(1,596.5)**	-
Proceeds from sale of assets	**18.7**	-
	(1,577.8)	-
Investments in jointly-controlled businesses		
Equity contributions	**(74.5)**	(68.8)
Return of capital	**11.2**	-
	(63.3)	(68.8)
Capital expenditures		
Midstream	**(14.3)**	(16.6)
Dasque-Middle run-of-river hydro facility	**(47.3)**	(23.7)
St. Columban wind project	**(83.2)**	-
Operating power facilities	**(1.6)**	(3.7)
AEGS pipeline extension	**-**	(1.8)
Other capital expenditures	**(1.4)**	(0.6)
	(147.8)	(46.4)
Other	**(1.5)**	(1.8)
Cash used in discontinued operations	**(3.8)**	(3.6)
Investing	**(1,794.2)**	(120.6)

Financing Activities
For the year ended December 31, 2014, we had $1,606.3 million of cash inflows to fund our financing activities, compared to $87.3 million cash used for the previous year. Financing activities for the years ended December 31, 2014 and 2013 included:

	Year ended December 31	
($ Millions)	**2014**	2013
Common Shares issued, net of issue costs	**1,156.9**	-
Common Share dividend payments	**(155.8)**	(155.1)
Net repayments of our Revolving Credit Facility	**(40.7)**	(60.0)
Long-term debt issued, net of issue costs	**920.4**	-
Senior debt repayments	**(261.8)**	(11.8)
October 2013 Series C Preferred Share offering, net of issue costs	**-**	144.8
Preferred Share dividend payments	**(16.3)**	(10.3)
Other	**3.6**	5.1
Financing	**1,606.3**	(87.3)

Equity Financing Activities
On April 3, 2014 we issued 17.3 million Common Shares at a price of $16.50 per share, providing gross proceeds of approximately $284.6 million. The net proceeds from the Offering were used to finance development costs relating to our proposed Jordan Cove LNG development project, to partially fund 2014 growth capital expenditures relating to our Dasque-Middle and St. Columban renewable power projects, to reduce our outstanding indebtedness and for general corporate purposes.

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™ to shareholders has substantially increased participation in our DRIP program, proving us with additional cash on hand to fund our various growth initiatives.

Debt Financing Activities
On June 10, 2014, we issued $200 million of senior unsecured medium term notes maturing on June 13, 2019, bearing interest at 3.06% per annum. The net proceeds of the offering were used on July 10, 2014 to redeem all of our outstanding $200 million senior notes, which were scheduled to mature on July 28, 2014.

In June 2014, the term of the Revolving Credit Facility was extended such that it now matures on May 31, 2018.

On May 30, 2014 we extinguished the remaining outstanding balance of $50.4 million of the Clowhom term loan, which was scheduled to mature on February 21, 2016.

On October 20, 2014, we redeemed the remaining $51.7 million balance of the 5.75% Convertible Unsecured Subordinated Debentures, Series C due July 31, 2017.

Ruby Acquisition Financing
To fund the Ruby acquisition, we utilized cash proceeds from our October subscription receipt offering and drawings on a new unsecured non-revolving term loan ("Acquisition Credit Facility").

On October 1, 2014 we issued 56.1 million subscription receipts at a price of $16.40 per subscription receipt for gross proceeds of approximately $920 million. This included the issuance of 7.3 million subscription receipts on the exercise in full of the over-allotment option granted to the underwriters, exercised concurrently with the closing of the offering.

The balance of the purchase price was funded with a $726 million drawing under the new Acquisition Credit Facility on November 6, 2014. The Acquisition Credit Facility ranks pari passu with our senior unsecured obligations, including our existing Revolving Credit Facility. It has a two-year term, maturing on November 6, 2016, and bears interest at a quoted floating rate plus a margin. Prepayments are permitted at our option at any time and upon the occurrence of certain events, in each case without premium or penalty.

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 4.4%, 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.

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, 2014 we declared dividends on our common shares of $227.2 million (2013 - $199.7 million), of which $146.0 million (2013 - $155.4 million) was paid to common shareholders in cash and $81.2 million (2013 - $44.3 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, 2014 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)	**2014**	2013	**2014**	2013
Cash from operating activities	**71.2**	83.7	**214.6**	217.4
Net income attributable to Common Shares	**21.0**	12.6	**52.4**	53.2
Dividends paid/payable	**66.3**	50.3	**227.2**	199.7
Less dividends paid in Common Shares under DRIP	**(42.4)**	(11.1)	**(81.2)**	(44.3)
Net dividends paid/payable	**23.9**	39.2	**146.0**	155.4
Excess of cash from operating activities over net dividends paid/payable	**47.3**	44.5	**68.6**	62.0
Deficiency of net income attributable to Common Shares over net dividends paid/payable	**(2.9)**	(26.6)	**(93.6)**	(102.2)

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 three months and year ended December 31, 2014, equity income from York Energy Centre includes a $3.8 million and a $12.3 million unrealized mark-to-market loss ($2.8 million and $9.2 million after tax), associated with an interest rate hedge. For the same periods last year, equity income from York Energy Centre includes a $2.0 million and $13.8 million unrealized mark-to-market gain, respectively ($1.5 million and $10.4 million after tax).

In 2014, we entered into forward foreign exchange contracts to manage the foreign exchange exposure relating to the Ruby acquisition. For the year ended December 31, 2014, we recognized a $38.7 million realized gain ($33.9 million after tax) associated with the forward foreign exchange contracts, included within foreign exchange and other in the Consolidated Statement of Income, classified within the Corporate segment (December 31, 2013 - nil). As the term of the contracts expired in November 2014, there are no unrealized foreign exchange hedging gains or losses at December 31, 2014 (December 31, 2013 - nil).

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 amortized cost	Non-financial instruments	**Total**	Fair value[1]
Assets					
Cash and short-term investments	51.4			**51.4**	51.4
Restricted cash	4.9			**4.9**	4.9
Distributions receivable	45.6			**45.6**	45.6
Receivables and accrued receivables	55.7			**55.7**	55.7
Due from jointly-controlled businesses	45.6			**45.6**	45.6
Assets held for sale	5.7		33.2	**38.9**	5.7
Investments held at cost	1,660.2			**1,660.2**	1,660.2
Other assets	1.6		16.8	**18.4**	1.6
Liabilities					
Payables, interest payable and accrued payables		68.7	2.0	**70.7**	68.7
Dividends payable		8.0		**8.0**	8.0
Liabilities associated with assets held for sale		3.6		**3.6**	3.6
Senior debt		1,811.4		**1,811.4**	1,864.3
Other long-term liabilities		14.3	38.5	**52.8**	14.3

(1) Fair value excludes non-financial instruments.

The following table summarizes our financial instrument carrying and fair values as at December 31, 2013:

($ Millions)	Financial assets at amortized cost	Financial liabilities at amortized cost	Non-financial instruments	**Total**	Fair value[2]
Assets					
Cash and short-term investments	25.2			**25.2**	25.2
Restricted cash	3.7			**3.7**	3.7
Distributions receivable	46.2			**46.2**	46.2
Receivables and accrued receivables	60.0			**60.0**	60.0
Due from jointly-controlled businesses	48.1			**48.1**	48.1
Assets held for sale	4.3		53.0	**57.3**	4.3
Other assets	1.6		13.3	**14.9**	1.6
Liabilities					
Payables, interest payable and accrued payables		47.7	2.4	**50.1**	47.7
Dividends payable		13.2		**13.2**	13.2
Liabilities associated with assets held for sale		3.3		**3.3**	3.3
Senior debt		1,187.5		**1,187.5**	1,226.3
Subordinated convertible debentures		86.2		**86.2**	91.6
Other long-term liabilities		10.2	38.3	**48.5**	10.2

(2) Fair value excludes non-financial instruments.

For the years ended December 31, 2014 and 2013 the following amounts were recognized in income:

($ Millions)	**2014**	2013
Total interest expense, recorded with respect to other financial liabilities, calculated using the effective rate method	**58.7**	61.9

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, subscription receipts 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 in Ruby approximates its carrying value due to the close proximity of the acquisition date to the balance sheet date. 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. The fair values of subordinated convertible debentures are measured at quoted market prices.

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.

Financial instruments measured at fair value as of December 31, 2014 were:

($ Millions)	Level 1	Level 2	Level 3	Total
Cash and short-term investments		51.4		51.4
Restricted cash		4.9		4.9
Investments held at cost			1,660.2	1,660.2

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, 2014:

($ Millions)	<1 year	1 - 3 years	4 - 5 years	Over 5 years
Payables, interest payable and accrued payables	68.7			
Dividends payable	8.0			
Liabilities associated with assets held for sale	3.6			
Senior debt	11.5	1,173.1	393.7	233.1
Other long-term liabilities		14.3		

The following table summarizes the maturity analysis of financial liabilities as of December 31, 2013:

($ Millions)	<1 year	1 - 3 years	4 - 5 years	Over 5 years
Payables, interest payable and accrued payables	47.7			
Dividends payable	13.2			
Liabilities associated with assets held for sale	3.3			
Senior debt	212.4	235.2	493.2	246.7
Subordinated convertible debentures			86.2	
Other long-term liabilities		10.2		

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

On March 30, 2012, a Statement of Claim was filed against our equity-accounted investees, Aux Sable Liquid Products, L.P., Aux Sable Canada L.P., Aux Sable Extraction LP and Aux Sable Canada Ltd., relating to differences in interpretation of certain terms of the NGL Sales Agreement. Our equity-accounted investees were served with this Statement of Claim on March 18, 2013. Our share of the potential exposure, through our equity investments, is approximately US$13.0 million (42.7%). Further potential differences in interpretation of certain terms of the NGL Sales Agreement have also been identified on additional years not currently the subject of any claims. We have recognized an estimated minimum amount within a range of possible amounts sufficient to potentially settle these claims. At this time, we are unable to predict the likely outcome of this matter. We will continue to assess the matter and the amount of loss accrued may change in the future.

Veresen will be filing an appeal of the decision issued on February 26, 2015 by an Ontario court relating to an application commenced by Energy Fundamentals Group Inc. ("EFG") for a declaration that, among other things, the option to acquire up to 20% of Veresen's equity interest in the Jordan Cove LNG terminal and related assets in Coos Bay, Oregon, granted to EFG pursuant to a 2005 letter agreement between the parties, continues to apply to our proposed Jordan Cove LNG export terminal. In its decision, the court declared that, among other things, the option continues to apply to the Jordan Cove LNG export project. Notice of the appeal must be served within a prescribed period of 30 days following the decision.

In September 2014, Aux Sable received a Notice of Violation ("NOV") from the United States Environmental Protection Agency ("EPA") for alleged violations of the Clean Air Act related to the Leak Detection and Repair program, and related provisions of the Clean Air Act permit for Aux Sable's Channahon, Illinois facility. As part of the ongoing process of responding to the NOV, Aux Sable discovered what it believes to be additional exceedance of currently permitted limits for Volatile Organic Material. Aux Sable is engaged in discussions with the EPA to evaluate the potential impact and ultimate resolution of these issues. At this time, we are unable to reasonably estimate the financial impact, if any, which might result from discussions with the EPA.

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	**1,811.4**	11.5	1,173.1	393.7	233.1
Operating leases	**54.9**	6.3	10.7	9.1	28.8
Other long-term obligations	**54.8**	2.0	14.3	-	38.5
	1,921.1	19.8	1,198.1	402.8	300.4

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 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

<u>Extension of Transportation Contracts; Supply and Demand</u>

Each of Alliance, Ruby, and AEGS derive revenues from transportation contracts with varying terms. Alliance contracts have a primary term ending on December 1, 2015. Ruby's weighted average primary contract term extends for approximately 9 years from November 2014. AEGS has primary terms ending on December 31, 2018. 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 the expiration of 92% of Alliance's current transportation service agreements on December 1, 2015, Alliance has applied to the NEB for approval of a New Services Offerings. The proposed New Services Offerings will provide a suite of transportation and rich gas services that can provide for the continued utilization of Alliance's transportation capacity and receipt of sufficient revenues to meet its financial requirements. Alliance has entered into binding precedent agreements for over 95% of total targeted capacity, a combination of receipt and full path, for an average contract length of approximately five years. There is no assurance that Alliance will receive approval of the application by the NEB in a manner acceptable to us.

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.

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;
- the exclusion of any cost of service amounts; and
- any other adverse change to the rates on the respective rate structures or terms and conditions of service.

In the case of Alliance, the ability to generate earnings and cash flows could further be adversely impacted if its regulators do not approve the proposed new service offerings and tolling methodologies.

Recovery of Capital
Alliance is permitted to recover from shippers costs incurred in the construction and operation of the pipeline system that are actually and reasonably incurred in accordance with NEB and FERC regulations. Alliance has firm transportation service agreements for 92% of its capacity until December 1, 2015. Alliance has made significant progress in its recontracting efforts with shippers post-2015 and precedent agreements for 95% of total targeted capacity are in place as of February 2015, with an average contract length of approximately five years. Beyond this timeframe, Alliance is exposed to economic risk associated with the recovery of capital.

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

As with any midstream natural gas business, 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. We believe the risk of lower throughput for the Dawson Assets is mitigated by commercial guarantees including financial protections. In addition, commercial efforts are underway to attract further third party volumes to our facilities. Volume risk is further mitigated by the continued high level of exploration and development activity in the Montney production area of British Columbia and Alberta, where theVeresen Midstream assets are located, an area widely recognized as one of North America's most promising and competitive natural gas resource plays.

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.

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. This basis is impacted by a number of factors, including weather events and forecasts, regional supply/demand dynamics, and overall pricing of North American natural gas. These factors could introduce more variability in Aux Sable's financial results post-November 2015. However, Aux Sable continues to implement strategies to minimize such variability.

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; 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. The forward foreign exchange contracts are further discussed in the *Financial Instruments* section of this MD&A. 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, 2014, approximately 50% of our total assets were denominated in U.S. dollars. For the year ended December 31, 2014, we recorded an unrealized foreign exchange gain of $69.4 million in other comprehensive income on the re-translation of our U.S. net assets. At December 31, 2014, 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 $23.8 million, $0.1 million, and $1.5 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 including the Acquisition Credit Facility. 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, 2014, 47% of our consolidated long-term debt was floating-rate debt. At December 31, 2014, 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 $8.5 million lower or higher.

As part of York Energy Centre's debt financing in 2010, it entered into two interest rate hedges. These hedges were entered into to manage the exposure to changes in interest rates whereby York Energy Centre receives variable interest rates and pays fixed interest rates. As at December 31, 2014, one interest rate hedge 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 and twelve months ended December 31, 2014, equity income from York Energy Centre includes a $3.8 million and $12.3 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, the majority of which are currently with 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. 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. 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, a major natural gas producer with investment-grade credit ratings. Future revenues will depend on Encana and CRP, a partnership between Encana and Cutbank Dawson Gas Resources Ltd., a subsidiary of Mitsubishi Corporation which has investment-grade credit ratings. 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 facilities), and individual counterparties with investment-grade ratings.

The transition to Alliance`s New Services Offerings will bring a new portfolio of shippers utilizing a variety of the new services offered, creating an evolving shipper credit mix and exposure. Alliance will continue to require shippers to provide letters of credit or other suitable security, unless the shippers maintain specified credit ratings or a suitable financial position. The risk of non-performance by potential shippers is also mitigated by the strong interest expressed in the New Services Offerings which has currently resulted in significant precedent agreement requests exceeding the level of firm capacity available.

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 exceedences, 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.
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.

We are unaware of any 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 conform 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 is subject to rate regulation in Canada and the United States. 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 are 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

We evaluate, at least annually, our long-lived assets 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$27.4 million. As a result, we recognized a $12.2 million impairment loss in the fourth quarter of 2014. We also recognized a $5.0 million impairment loss on land we hold in Ontario.

In our view, at December 31, 2014, there has not been impairment in the carried value of our long-lived assets other than in the assets described above.

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, the Hythe/Steeprock complex, and the EnPower, East Windsor Cogeneration, Furry Creek and Clowhom 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

The following new Accounting Standards Updates (“ASU”) have been issued, as of December 31, 2014.

Effective January 1, 2014, we adopted Accounting Standards Update ("ASU") 2013-04 "*Obligations Resulting from Joint and Several Liability Arrangements*". This ASU provides guidance on disclosure and measurement for obligations with fixed amounts at a reporting date resulting from joint and several liability arrangements. This guidance was applied retrospectively and did not have a material impact to us.

Effective January 1, 2014, we adopted ASU 2013-05 "*Foreign Currency Matters: Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Invesment in a Foreign Entity*". This ASU provides guidance for transactions that require the entire amount of a cumulative translation adjustment related to an entity's investment in a foreign entity to be released. This guidance was applied retrospectively and did not have a material impact to us.

In April 2014, the FASB issued 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 is effective for annual and interim periods beginning after December 15, 2014, and is to be applied prospectively. It is anticipated that in general, the revised criteria will result in fewer transactions being categorized as discontinued operations.

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. 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. This guidance is effective for annual and interim periods beginning after December 15, 2014, is to be applied prospectively, and will not have a material impact on us.

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.

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 transaction costs incurred in conjunction with acquisitions. 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 transaction costs to be part of the consideration paid for an acquired business and, as such, are unrelated to our operating businesses. 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	
($ Millions)	**2014**	2013	**2014**	2013
Cash from operating activities	**71.2**	83.7	**214.6**	217.4
Add (deduct):				
Project development costs [1]	**20.0**	9.6	**78.8**	33.5
Change in non-cash working capital	**(14.5)**	(29.0)	**(8.2)**	(6.0)
Principal repayments on senior notes	**(2.9)**	(3.1)	**(11.5)**	(11.8)
Maintenance capital expenditures	**(1.4)**	(0.8)	**(6.1)**	(5.8)
Distributions earned greater (less) than distributions received [2]	**(1.5)**	(2.3)	**(5.0)**	8.0
Preferred Share dividends	**(4.0)**	(3.7)	**(16.3)**	(10.3)
Current tax on Preferred Share dividends	**1.6**	1.4	**6.4**	3.9
Distributable cash	**68.5**	55.8	**252.7**	228.9

(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, 2014 relate primarily to the Jordan Cove LNG terminal project, the Pacific Connector Gas Pipeline project, and various power 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.

($ Millions)	Three months ended December 31 **2014**	2013	Year ended December 31 **2014**	2013
Adjusted net income attributable to Common Shares	**8.6**	11.7	**30.7**	40.5
Power - net income (loss) from discontinued operations before tax (1)	**(15.9)**	(0.9)	**(16.0)**	3.8
Power - unrealized gain (loss) on interest rate hedge (2)	**(3.8)**	2.0	**(12.3)**	13.8
Corporate - gain on sale of assets (3)	**-**	-	**14.3**	-
Corporate - gain on forward foreign exchange contracts (4)	**33.8**	-	**38.7**	-
Corporate - asset impairment loss (5)	**(5.0)**	-	**(5.0)**	-
Taxes (6)	**3.3**	(0.2)	**2.0**	(4.9)
Net income attributable to Common Shares	**21.0**	12.6	**52.4**	53.2

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) Results relating to three U.S. gas-fired assets that were sold January 8, 2015. Included in the results is a $12.2 million impairment loss recognized in the fourth quarter of 2014.

(2) York Energy Centre, a jointly-controlled business, has one interest rate hedge. Future changes in interest rates affect the fair value of the hedge, impacting the amount of unrealized gains and losses included in equity income from jointly-controlled businesses recognized in the period.

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

(4) Gains on the forward foreign exchange contracts we entered into to manage the foreign exchange exposure relating to the Ruby acquisition.

(5) Impairment of land we own in Ontario.

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

SELECTED QUARTERLY FINANCIAL INFORMATION

($ Millions, except where noted)	2014 **Q4**	Q3 (1)	Q2 (1)	Q1 (1)	2013 Q4 (1)	Q3 (1)	Q2 (1)	Q1 (1)
Operating revenues	**68.0**	68.1	79.4	86.6	71.7	72.2	80.9	66.9
Net income attributable to Common Shares	**21.0**	2.5	(2.4)	31.3	12.6	27.9	11.5	1.2
Net income per Common Share ($) – basic and diluted	**0.08**	0.01	(0.01)	0.16	0.06	0.14	0.06	0.01
Distributable cash	**68.5**	54.9	63.7	65.6	55.8	69.3	49.2	54.6
Distributable cash per Common Share ($) – basic and diluted	**0.26**	0.24	0.29	0.33	0.28	0.35	0.25	0.27
Cash from operating activities	**71.2**	50.0	48.8	44.6	83.7	41.2	56.6	35.9

(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 2014 reflects 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.
- Fourth quarter 2013 reflected continued weakness in ethane market conditions, increased finance costs and higher Corporate costs.
- Third quarter 2013 reflected improved margin-based lease revenues for Aux Sable and higher contributions from Hythe/Steeprock.
- Second quarter 2013 reflected continued weakness in NGL market conditions and increased finance costs.
- First quarter 2013 reflected continued weakness in NGL market conditions and increased administrative and finance costs.

RELATED PARTY TRANSACTIONS

On March 30, 2012, we provided a $47.0 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, 2014, the outstanding balance was $43.0 million (2013 - $44.5 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, 2014.

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, 2014 in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO) 2013 Internal Control - Integrated Framework, and, based on that assessment, determined with reasonable assurance that 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.

No changes were made to internal controls over financial reporting during the period ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.