UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

OR

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013
Commission File Number 001-15150

ENERPLUS CORPORATION

(Exact name of Registrant as specified in its charter)

Alberta, Canada	**1311**	**N/A**
(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number (if applicable))	(I.R.S. Employer Identification Number (if applicable))

The Dome Tower, 3000, 333 - 7th Avenue S.W.
Calgary, Alberta, Canada T2P 2Z1
(403) 298-2200
(Address and telephone number of Registrant's principal executive offices)

CT Corporation System
111 Eighth Avenue, 13th Floor
New York, New York 10011
(212) 894-8940
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:

Title of each class	**Name of each exchange on which registered**
Common Shares	Toronto Stock Exchange The New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: None

For annual reports, indicate by check mark the information filed with this Form:

☒ Annual information form ☒ Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.

202,757,689 Common Shares

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☒ No ☐

FORWARD-LOOKING STATEMENTS

This Annual Report on Form 40-F contains or incorporates by reference forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Registrant. Undue reliance should not be placed on these forward-looking statements which are based upon management's assumptions and are subject to known and unknown risks and uncertainties which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted. For a description of some of these risks, uncertainties, events and circumstances, readers should review the disclosure under the heading "Risk Factors" in the Registrant's Annual Information Form for the year ended December 31, 2013, which is attached as Exhibit 99.1 to this Annual Report on Form 40-F and is incorporated by reference herein. Other than as required by applicable law, the Registrant undertakes no obligation to update publicly or revise any forward-looking statements contained herein and such statements are expressly qualified by the cautionary statement.

ANNUAL INFORMATION FORM, AUDITED ANNUAL CONSOLIDATED FINANCIAL STATEMENTS AND MANAGEMENT'S DISCUSSION AND ANALYSIS

A. Annual Information Form

The Registrant's Annual Information Form for the year ended December 31, 2013 is attached as Exhibit 99.1 to this Annual Report on Form 40-F and is incorporated by reference herein.

B. Audited Annual Consolidated Financial Statements

The Registrant's audited annual consolidated financial statements for the year ended December 31, 2013, including the report of the independent registered chartered accountants with respect thereto, are attached as Exhibit 99.2 to this Annual Report on Form 40-F and are incorporated by reference herein.

C. Management's Discussion and Analysis

The Registrant's Management's Discussion and Analysis for the year ended December 31, 2013 is attached as Exhibit 99.3 to this Annual Report on Form 40-F and is incorporated by reference herein.

DISCLOSURE REGARDING CONTROLS AND PROCEDURES

A. Disclosure Controls and Procedures

As of the end of the Registrant's fiscal year ended December 31, 2013, an evaluation of the effectiveness of the Registrant's "disclosure controls and procedures" (as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) was carried out by the Registrant's principal executive officer and principal financial officer. Based upon that evaluation, the Registrant's principal executive officer and principal financial officer have concluded that as of the end of that fiscal year, the Registrant's disclosure controls and procedures (which include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrant in the reports that it files or submits under the Securities Exchange Act of 1934 is accumulated and communicated to the Registrant's management, including its principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow for timely decisions regarding required disclosure) are effective to ensure that the information required to be disclosed by the Registrant in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in Securities and Exchange Commission rules and forms.

B. Management's Annual Report on Internal Control Over Financial Reporting

The Registrant's report of management on the Registrant's internal control over financial reporting is included under the heading "Management's Report on Internal Control Over Financial Reporting" contained in Exhibit 99.2 to this Annual Report on Form 40-F, which report of management is incorporated by reference herein.

C. Attestation Report of the Registered Public Accounting Firm

The attestation report of the independent registered chartered accountants on the effectiveness of internal control over financial reporting is included under the heading "Report of Independent Registered Public Accounting Firm" contained in Exhibit 99.2 to this Annual Report on Form 40-F, which attestation report is incorporated by reference herein.

D. Changes in Internal Control over Financing Reporting

During the fiscal year ended December 31, 2013, there were no changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

None.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the Registrant has determined that Mr. Robert B. Hodgins, a member and the chairman of the Registrant's Audit & Risk Management Committee, is an "audit committee financial expert" (as such term is defined by the rules and regulations of the Securities and Exchange Commission) and is "independent" (as that term is defined by the New York Stock Exchange's listing standards applicable to the Registrant).

The Securities and Exchange Commission has indicated that the designation or identification of a person as an "audit committee financial expert" does not (i) mean that such person is an "expert" for any purpose, including without limitation for purposes of Section 11 of the Securities Act of 1933, (ii) impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the audit committee and the board of directors in the absence of such designation or identification, or (iii) affect the duties, obligations or liability of any other member of the audit committee or the board of directors.

CODE OF ETHICS

The Registrant has adopted a "code of ethics" (as that term is defined by the rules and regulations of the Securities and Exchange Commission), entitled the "Code of Business Conduct" (as amended to the date of this Form 40-F, the "Code of Business Conduct"), that applies to each director, officer (including its principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions), employee and consultant of the Registrant. The Registrant amended the Code of Business Conduct effective January 31, 2013. The only amendment of a substantive nature was the addition of more comprehensive anti-corruption practices. During the fiscal year ended December 31, 2013, there were no waivers, including implicit waivers, granted from any provision of the Code of Business Conduct that applied to the Registrant's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions.

The Code of Business Conduct is attached as Exhibit 99.11 to this Annual Report on Form 40-F and is incorporated by reference herein.

PRINCIPAL ACCOUNTANT FEES AND SERVICES AND PRE-APPROVAL POLICIES AND PROCEDURES

The aggregate fees paid by the Registrant to Deloitte LLP, Independent Registered Public Accounting Firm, the Registrant's principal accountant, for professional services rendered in the Registrant's last two fiscal years are as follows:

	2013	2012
	(in Cdn$ thousands)	
Audit fees(1)	965.9	809.9
Audit-related fees(2)	—	—
Tax fees(3)	500.5	678.9
All other fees(4)	—	—
Total	1,466.4	1,488.8

(1) Audit fees were for professional services rendered by Deloitte LLP for the audit of the Registrant's annual financial statements and reviews of the Registrant's quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees are fees for assurance and related services reasonably related to the performance of the audit or review of the Registrant's financial statements and not reported under "Audit Fees" above.

(3) Tax fees were for tax compliance, tax advice and tax planning.

(4) All other fees are fees for products and services provided by Deloitte LLP other than those described as "Audit fees", "Audit-related fees" and "Tax fees".

The Registrant's Audit & Risk Management Committee has implemented a policy restricting the services that may be provided by the Registrant's auditors and the fees paid to the Registrant's auditors. Prior to the engagement of the Registrant's auditors to perform both audit and non-audit services, the Audit & Risk Management Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Audit & Risk Management Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding an adverse impact on auditor independence. All audit and non-audit fees paid to Deloitte LLP in 2012 and 2013 were pre-approved by the Registrant's Audit & Risk Management Committee and none were approved on the basis of the de minimis exemption set forth in Rule 2-01(c)(7)(i)(C) of Regulation S-X. Based on the Audit & Risk Management Committee's discussions with management and the independent auditors, the committee is of the view that the provision of the non-audit services by Deloitte LLP described above is compatible with maintaining that firm's independence from the Registrant.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant has no off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on the Registrant's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The following table sets forth the Registrant's known contractual obligations as of December 31, 2013:

	Payments due by period (in Cdn$ thousands)				
Contractual Obligations[1]	Total	2014	2015 to 2016	2017 to 2018	2019 +
Bank credit facility	$ 214,394	$ —	$ 214,394	$ —	$ —
Senior unsecured notes[2]	810,904	48,713	94,031	95,724	572,436
Transportation commitments	102,677	30,416	38,869	15,513	17,879
Processing commitments	50,593	10,250	18,624	14,949	6,770
Drilling and completions commitment	11,582	11,582	—	—	—
Power infrastructure	13,913	4,020	9,893	—	—
Asset retirement obligations[3]	720,620	26,550	54,000	54,000	586,070
Office leases	73,056	13,611	23,928	24,807	10,710
Total commitments[4]	$ 1,997,739	$ 145,142	$ 453,739	$ 204,993	$ 1,193,865

Notes:

(1) U.S. dollar commitments have been converted to Canadian dollars using the December 31, 2013 foreign exchange rate of Cdn$1.00 = US$0.94.

(2) Interest payments have not been included.

(3) Based on the Registrant's current spending estimates.

(4) Crown and surface royalties, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.

Additional disclosure regarding the Registrant's contractual obligations as of December 31, 2013 is provided under the heading "Liquidity and Capital Resources—Commitments" in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2013 attached as Exhibit 99.3 to this Annual Report on Form 40-F, which disclosure is incorporated by reference herein, and in Note 16 to the Registrant's audited annual consolidated financial statements for the year ended December 31, 2013 attached as Exhibit 99.2 to this Annual Report on Form 40-F, which note is incorporated by reference herein.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing audit committee established in accordance with section 3(a)(58)(A) of the Exchange Act. The members of the Registrant's Audit & Risk Management Committee are Robert B. Hodgins (as Chairman), Elliott Pew, Glen D. Roane and Sheldon B. Steeves. Douglas R. Martin, the chairman of the board of directors of the Registrant, is an *ex officio* member of the Audit & Risk Management Committee.

COMPLIANCE WITH NYSE CORPORATE GOVERNANCE RULES

The Registrant has reviewed the New York Stock Exchange's corporate governance rules and confirms that the Registrant's corporate governance practices are not significantly nor materially different than those required of domestic companies under the New York Stock Exchange's listing standards except that, as a foreign private issuer.

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

A. Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

B. Consent to Service of Process

1. The Registrant previously filed with the Commission a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

2. Any change to the name or address of the Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

ENERPLUS CORPORATION

By: /s/ IAN C. DUNDAS

Ian C. Dundas
President and Chief Executive Officer

Date: February 21, 2014

EXHIBIT INDEX

99.1	Annual Information Form for the year ended December 31, 2013 dated February 21, 2014.
99.2	Audited annual consolidated financial statements for the year ended December 31, 2013.
99.3	Management's Discussion and Analysis for the year ended December 31, 2013.
99.4	Consent of Independent Registered Public Accounting Firm.
99.5	Consent of McDaniel & Associates Consultants Ltd.
99.6	Consent of Netherland, Sewell & Associates, Inc.
99.7	Certification of the Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934.
99.8	Certification of the Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934.
99.9	Certification of the Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.10	Certification of the Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.11	Code of Business Conduct dated January 31, 2013.
101	Interactive Data File

Exhibit 99.1

ANNUAL INFORMATION FORM
For the year ended December 31, 2013

February 21, 2014

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Glossary of Terms

Unless the context otherwise requires, in this Annual Information Form, the following terms and abbreviations have the meanings set forth below. **Additional terms relating to oil and natural gas reserves, resources and operations have the meanings set forth under "*Presentation of Oil and Gas Reserves, Resources and Production Information*".**

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended;

"**AECO**" means the physical storage and trading hub for natural gas on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta index prices;

"**Bank Credit Facility**" means, as of December 31, 2013, the Corporation's $1.0 billion unsecured, covenant-based revolving credit facility with a syndicate of financial institutions: see "*Material Contracts and Documents Affecting the Rights of Securityholders*";

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time;

"**Common Shares**" means the common shares in the capital of the Corporation;

"**Conversion**" means the conversion of Enerplus' business from an income trust structure (with the parent entity being the Fund) to a corporate structure (with the parent entity being the Corporation) effective January 1, 2011 by way of a plan of arrangement under the ABCA, pursuant to which, among other things, the former trust units of the Fund, each of which represented an equal undivided beneficial interest in the Fund ("**Trust Units**"), were exchanged on a one-for-one basis for Common Shares;

"**Corporation**" means Enerplus Corporation, a corporation amalgamated under the ABCA, and, where the context applies, its subsidiaries, taken as a whole;

"**Credit Facilities**" means, collectively, the Bank Credit Facility and the Senior Unsecured Notes. See "*Material Contracts and Documents Affecting the Rights of Securityholders*";

"**CSA Notice 51-324**" means Canadian Securities Administrators Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities*, issued by the Canadian securities regulatory authorities;

"**Enerplus**" means (i) on and after January 1, 2011, the Corporation and, where the context applies, its subsidiaries, taken as a whole, and (ii) prior to January 1, 2011, the Fund and its subsidiaries, taken as a whole;

"**Enerplus USA**" means Enerplus Resources (USA) Corporation, a corporation organized under the laws of Delaware and a wholly-owned subsidiary of the Corporation;

"**Fund**" means Enerplus Resources Fund, formerly a trust formed pursuant to the laws of Alberta that was dissolved on January 1, 2011 in connection with the Conversion, and which was the predecessor issuer to the Corporation;

"**IFRS**" means International Financial Reporting Standards, as issued by the International Accounting Standards Board, as amended from time to time;

"**Laricina**" means Laricina Energy Ltd., a private corporation organized under the ABCA;

"**McDaniel**" means McDaniel & Associates Consultants Limited, independent petroleum consultants;

"**McDaniel Reports**" means, collectively, the independent engineering evaluations of the Corporation's oil, NGLs and natural gas reserves in Canada and the Corporation's oil, NGLs and natural gas reserves in the United States prepared by McDaniel effective December 31, 2013, utilizing commodity price forecasts of McDaniel as of January 1, 2014;

"**MD&A**" means management's discussion and analysis;

"**NSAI**" means Netherland, Sewell & Associates, Inc., independent petroleum consultants;

"**NSAI Reports**" means, collectively, the independent engineering evaluations of the Corporation's oil, NGLs, natural gas and shale gas reserves and contingent resources in the Marcellus properties and the natural gas and NGLs reserves in the Jonah field prepared by NSAI effective

December 31, 2013, utilizing commodity price forecasts of McDaniel (for internal consistency in the Corporation's reserves reporting) as of January 1, 2014;

"**NI 51-101**" means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*, adopted by the Canadian securities regulatory authorities;

"**NYSE**" means the New York Stock Exchange;

"**SEC**" means the United States Securities and Exchange Commission;

"**Senior Unsecured Notes**" means, as at December 31, 2013, the US$696.6 million principal amount and $70.0 million principal amount of outstanding senior unsecured notes issued by Enerplus. See "*Description of Capital Structure – Senior Unsecured Notes*" and "*Material Contracts and Documents Affecting the Rights of Securityholders*";

"**Shareholder Rights Plan**" means the amended and restated shareholder rights plan agreement between the Corporation and Computershare Trust Company of Canada, as rights agent, dated as of May 10, 2013;

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c.1 (5th Supp.), as amended, including the regulations promulgated thereunder, as amended from time to time;

"**TSX**" means the Toronto Stock Exchange; and

"**U.S. GAAP**" means generally accepted accounting principles in the United States.

Abbreviations and Conversions

In this Annual Information Form, the following abbreviations have the meanings set forth below:

API	American Petroleum Institute
bbls	barrels, with each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/day	barrels per day
Bcf	billion cubic feet
Bcf/day	billion cubic feet per day
BcfGE(1)	one billion cubic feet of natural gas equivalent
BOE(1)	barrels of oil equivalent
BOE/day	barrels of oil equivalent per day
Mbbls	one thousand barrels
MBOE(1)	one thousand barrels of oil equivalent
Mcf	one thousand cubic feet
Mcf/day	one thousand cubic feet per day
McfGE(1)	one thousand cubic feet of natural gas equivalent
McfGE/day	one thousand cubic feet of natural gas equivalent per day
MMbbls	one million barrels
MMBOE(1)	one million barrels of oil equivalent
MMbtu	one million British Thermal Units
MMcf	one million cubic feet
MMcf/day	one million cubic feet per day
MMcfGE/day	one million cubic feet of natural gas equivalent per day
NGLs	natural gas liquids
NYMEX	the New York Mercantile Exchange
WTI	West Texas Intermediate crude oil that serves as the benchmark crude oil for the NYMEX crude oil contract delivered in Cushing, Oklahoma

Note:

(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to McfGEs, MMcfGEs and BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Barrels of Oil and Cubic Feet of Gas Equivalent*".

In this Annual Information Form, unless otherwise indicated, all dollar amounts are in Canadian dollars and all references to "**$**" and "**CDN$**" are to Canadian dollars. References to "**US$**" are to U.S. dollars. On December 31, 2013, the exchange rate for one U.S. dollar, expressed in Canadian dollars and based upon the noon buying rate of the Bank of Canada, was CDN$1.0636.

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

Presentation of Oil and Gas
Reserves, Resources and Production Information

NOTE TO READER REGARDING OIL AND GAS INFORMATION, DEFINITIONS AND NATIONAL INSTRUMENT 51-101

The oil and gas reserves and operational information of the Corporation contained in this Annual Information Form contains the information required to be included in the Statement of Reserves Data and Other Oil and Gas Information pursuant to NI 51-101 adopted by the Canadian securities regulatory authorities. Readers should also refer to the Report on Reserves Data by McDaniel attached hereto as Appendix A, the Report on Reserves Data by NSAI attached as Appendix B and the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix C. The effective date for the Statement of Reserves Data and Other Oil and Gas Information contained in this Annual Information Form is December 31, 2013 and the preparation dates for such information are January 29, 2014 for the McDaniel Reports and January 21, 2014 for the NSAI Reports.

Certain of the following definitions and guidelines are contained in the Glossary to NI 51-101 contained in CSA Notice 51-324, which incorporates certain definitions from the COGE Handbook. Readers should consult CSA Notice 51-324 and the COGE Handbook for additional explanation and guidance.

DISCLOSURE OF RESERVES AND PRODUCTION INFORMATION

Presentation of Information

In this Annual Information Form, all oil and natural gas production and realized product prices information is presented on a "company interest" basis (as defined below), unless expressly indicated that it is being presented on a "gross" or "net" basis. "**Company interest**" means, in relation to the Corporation's interest in production, its working interest (operating or non-operating) share before deduction of royalties, plus the Corporation's royalty interests in production. "Company interest" is not a term defined or recognized under NI 51-101 and does not have a standardized meaning under NI 51-101. Therefore, the "company interest" production of the Corporation may not be comparable to similar measures presented by other issuers, and investors are cautioned that "company interest" production should not be construed as an alternative to "gross" or "net" production calculated in accordance with NI 51-101.

The Corporation's actual oil and natural gas reserves and future production may be greater than or less than the estimates provided in this Annual Information Form. The estimated future net revenue from the production of such oil and natural gas reserves does not represent the fair market value of such reserves. See "*Oil and Natural Gas Reserves – Summary of Reserves*" for additional information.

Notice to U.S. Readers

Data on oil and natural gas reserves contained in this Annual Information Form has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, although the SEC now generally permits oil and gas issuers, in their filings with the SEC, to disclose both proved reserves and probable reserves (each as defined in the SEC rules), the SEC definitions of proved reserves and probable reserves may differ from the definitions of "proved reserves" and "probable reserves" under Canadian securities laws. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above with respect to production information, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Moreover, in accordance with Canadian disclosure requirements, the Corporation has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC now generally requires that reserve estimates be prepared using an unweighted average of the closing prices for the applicable commodity on the first day of each of the twelve months preceding the company's fiscal year-end, with the option of also disclosing reserve estimates based upon future or other prices. As a consequence of the foregoing, the Corporation's reserve estimates and production volumes may not be comparable to those made by companies utilizing United States reporting and disclosure standards. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings, including contingent resources, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed as, reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "– *Disclosure of Contingent Resources*" below.

Notwithstanding the above, Enerplus has included as Appendix E to this Annual Information Form certain disclosure relating to Enerplus' oil and gas reserves and operations in accordance with the Financial Accounting Standards Board's Accounting Standards Update (ASU) No. 2010-03 "*Extractive Activities – Oil and Gas (Topic 932)*", which disclosure complies with the SEC's guidelines regarding disclosure of oil and gas reserves.

BARRELS OF OIL AND CUBIC FEET OF GAS EQUIVALENT

The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to McfGEs, MMcfGEs and BcfGEs. BOEs, MBOEs, MMBOEs, McfGEs, MMcfGEs and BcfGEs may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

DISCLOSURE OF CONTINGENT RESOURCES

In this Annual Information Form, the Corporation has disclosed estimated volumes of economic "contingent resources" which relate to the Corporation's interests in its Fort Berthold property located in North Dakota, its Marcellus shale gas properties located in Pennsylvania, its crude oil waterflood properties located in Alberta and Saskatchewan and its Wilrich natural gas assets located in Alberta.

"**Resources**" are quantities of petroleum that are estimated to exist originally in naturally occurring accumulations, including the quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered.

"**Contingent resources**" are defined as those quantities of hydrocarbons estimated, on a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early project stage. "Economic" contingent resources are those resources that are currently economically recoverable.

The economic contingent resource estimates in this Annual Information Form are presented as the "**best estimate**" of the quantity that will actually be recovered, meaning that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate. The recovery and resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

Resources and contingent resources do not constitute, and should not be confused with, reserves. See "*Business of the Corporation – Description of Properties*" and "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserve and resource estimates, and those variations could be material*".

INTERESTS IN RESERVES, PRODUCTION, WELLS AND PROPERTIES

In addition to the terms having defined meanings set forth in CSA Notice 51-324, the terms set forth below have the following meanings when used in this Annual Information Form:

"**gross**" means:

(i) in relation to the Corporation's interest in production or reserves, its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;

(ii) in relation to wells, the total number of wells in which the Corporation has an interest; and

(iii) in relation to properties, the total area in which the Corporation has an interest.

"**net**" means:

(i) in relation to the Corporation's interest in production or reserves, its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in production or reserves;

(ii) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and

(iii) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"**working interest**" means the percentage of undivided interest held by the Corporation in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the Corporation the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

RESERVES CATEGORIES AND LEVELS OF CERTAINTY FOR REPORTED RESERVES

In this Annual Information Form, the following terms have the meaning assigned thereto in CSA Notice 51-324 and the COGE Handbook:

"**reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed. Reserves may be divided into proved and probable categories according to the degree of certainty associated with the estimates.

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

DEVELOPMENT AND PRODUCTION STATUS

Each of the reserves categories reported by the Corporation (proved and probable) may be divided into developed and undeveloped categories:

"**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

- "**developed producing reserves**" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- "**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved or probable) to which they are assigned.

DESCRIPTION OF PRICE AND COST ASSUMPTIONS

"**Forecast prices and costs**" means future prices and costs that are:

(i) generally accepted as being a reasonable outlook of the future; and

(ii) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices or costs referred to in paragraph (i).

Presentation of Financial Information

We have converted our financial reporting from IFRS to U.S. GAAP as (i) over 50% of the book value of our assets (as previously calculated under IFRS) was in the United States, and (ii) over 50% of our Common Shares are held by U.S. residents. Reporting under U.S. GAAP began with our financial statements for the year ended December 31, 2013, with comparatives for 2012 and 2011.

We continue to qualify as a foreign private issuer for our U.S. securities filings as less than 50% of the book value of our assets is in the United States, as calculated under U.S. GAAP as at June 30, 2013. We are required to reassess this annually at the end of our second quarter, and should our U.S. asset book value exceed 50% of our corporate total, we would fail to qualify as a foreign private issuer and would become subject to U.S. domestic filing requirements effective the first day of the following calendar year. See "*Risk Factors – Government regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs*".

Forward-Looking Statements and Information

This Annual Information Form contains certain forward-looking statements and forward-looking information (collectively, "forward-looking information") within the meaning of applicable securities laws which are based on the Corporation's current internal expectations, estimates, projections, assumptions and beliefs. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "plan", "intend", "guidance", "objective", "strategy", "should", "believe" and similar expressions are intended to identify forward-looking statements and forward-looking information. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Corporation believes the expectations reflected in such forward-looking information are reasonable but no assurance can be given that these expectations will prove to be correct, and such forward-looking information included in this Annual Information Form should not be unduly relied upon. Such forward-looking information speaks only as of the date of this Annual Information Form and the Corporation does not undertake any obligation to publicly update or revise any forward-looking information, except as required by applicable laws.

In particular, this Annual Information Form contains forward-looking information pertaining to the following:

- the quantity of, and future net revenues from, the Corporation's reserves and/or contingent resources;
- crude oil, NGLs, natural gas and shale gas production levels;
- commodity prices, foreign currency exchange rates and interest rates;
- capital expenditure programs, drilling programs, development plans and other future expenditures, including the planned allocation of capital expenditures among the Corporation's properties, the timing of capital expenditures and the sources of funding for such expenditures;
- supply and demand for oil, NGLs and natural gas;
- the Corporation's business strategy, including its asset and operational focus;
- future acquisitions and dispositions and future growth potential;
- expectations regarding the Corporation's ability to raise capital and to continually add to reserves and/or resources through acquisitions and development;
- schedules for and timing of certain projects and the Corporation's strategy for growth;
- the Corporation's future operating and financial results;
- future abandonment and reclamation costs;
- future dividends that may be paid by the Corporation;
- the Corporation's tax pools and the time at which the Corporation may incur certain income or other taxes; and
- treatment under governmental and other regulatory regimes and tax, environmental and other laws.

The forward-looking information contained in this Annual Information Form reflect several material factors and expectations and assumptions made by the Corporation including, without limitation, that: the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; the Corporation's conduct and results of operations will be consistent with its expectations; the Corporation and its industry partners will have the ability to develop the Corporation's oil and gas properties in the manner currently contemplated; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; the estimates of the Corporation's reserves and resources volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; there will be sufficient availability of services and labour to conduct the Corporation's operations as planned; and the Corporation's commodity price and other cost assumptions will generally be accurate. The Corporation believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable at this time but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The Corporation's actual results could differ materially from those anticipated in these forward-looking information as a result of both known and unknown risks, including the risk factors set forth under "*Risk Factors*" in this Annual Information Form and risks relating to:

- volatility in market prices for oil, NGLs, natural gas and shale gas, including changes in supply or demand for those products;

- actions by governmental or regulatory authorities including different interpretations of applicable laws, treaties or administrative positions as well as changes in income tax laws or changes in royalty regimes and incentive programs relating to the oil and gas industry;
- unanticipated operating results including changes or fluctuations in oil, NGLs and natural gas production levels;
- changes in foreign currency exchange rates and interest rates;
- changes in development plans by the Corporation or third party operators;
- the ability of the Corporation to access required capital;
- changes in capital and other expenditure requirements and debt service requirements;
- liabilities and unexpected events inherent in oil and gas operations, including geological, technical, drilling and processing risks, as well as unforeseen title defects or litigation;
- actions of and reliance on industry partners;
- uncertainties associated with estimating reserves and resources;
- competition for, among other things, capital, acquisitions of reserves and resources, undeveloped lands, access to third party processing capacity and skilled personnel;
- incorrect assessments of the value of acquisitions or the failure to complete dispositions;
- constraints on, or the unavailability of, adequate pipeline and transportation capacity to deliver the Corporation's production to market;
- the Corporation's success at the acquisition, exploitation and development of reserves and resources;
- changes in general economic, market (including credit market) and business conditions in Canada, North America and worldwide; and
- changes in tax, environmental, regulatory or other legislation applicable to the Corporation and its operations, and the Corporation's ability to comply with current and future environmental legislation and regulations and other laws and regulations.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this Annual Information Form and in the Corporation's MD&A for the year ended December 31, 2013, which is available through the internet on the Corporation's SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov as part of the annual report on Form 40-F filed with the SEC together with this Annual Information Form, and on the Corporation's website at www.enerplus.com. Readers are also referred to the risk factors described in this Annual Information Form under "*Risk Factors*" and in other documents the Corporation files from time to time with securities regulatory authorities. Copies of these documents are available without charge from the Corporation or electronically on the internet on the Corporation's SEDAR profile at www.sedar.com, on the Corporation's EDGAR profile at www.sec.gov and on the Corporation's website at www.enerplus.com.

Corporate Structure

ENERPLUS CORPORATION

The Corporation was incorporated on August 12, 2010 under the ABCA for the purposes of participating in the Conversion under which the business of Enerplus Resources Fund, as the Corporation's predecessor, was transitioned to the Corporation. As part of the plan of arrangement under the ABCA pursuant to which the Conversion was effected, the Corporation was amalgamated with several other former direct and indirect subsidiaries of the Fund on January 1, 2011 and continued as the Corporation. See "*General Development of the Business – Developments in the Past Three Years – Developments in 2011 – Conversion from an Income Trust to a Corporation*". Prior to the Conversion, the business of the Corporation was carried on by the Fund and its subsidiaries as an income trust since 1986.

Effective May 11, 2012, the Corporation amended and restated its articles of amalgamation in connection with the implementation of a stock dividend program. The Corporation amended the rights, privileges, restrictions and conditions in respect of Common Shares to set forth the terms and conditions pursuant to which the Corporation may issue Common Shares as payment of all or any portion of dividends declared on the Common Shares for those shareholders who elect to receive stock dividends instead of cash dividends. See "*Description of Capital Structure – Common Shares*" and "*Dividends and Distributions – Stock Dividend Program*".

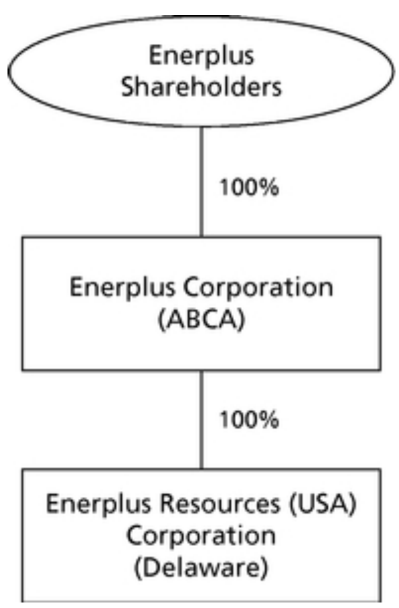
The head, principal and registered office of the Corporation is located at The Dome Tower, 3000, 333 - 7th Avenue S.W., Calgary, Alberta, T2P 2Z1. The Corporation also has a U.S. office located at 950 - 17th Street, Suite 2200, Denver, Colorado, 80202-2805. The Common Shares are currently traded on the TSX and the NYSE under the symbol "ERF".

MATERIAL SUBSIDIARIES

As of December 31, 2013, Enerplus USA was the only material subsidiary of Enerplus Corporation. All of the issued and outstanding securities of Enerplus USA are owned by the Corporation.

ORGANIZATIONAL STRUCTURE

The simplified organizational structure of Enerplus Corporation and its material subsidiary as of December 31, 2013 is set forth below.



General Development of the Business

DEVELOPMENTS IN THE PAST THREE YEARS

Developments in 2011

CONVERSION FROM AN INCOME TRUST TO A CORPORATION

As a result of legislative changes implemented in June of 2007 that subjected certain types of publicly traded mutual fund trusts, such as the Fund, to tax at rates comparable to the combined federal and provincial corporate tax rates beginning in the 2011 tax year, Enerplus completed the Conversion on January 1, 2011 pursuant to a plan of arrangement under the ABCA. The Conversion, together with a related internal corporate reorganization, resulted in the business and structure of Enerplus being reorganized from an income trust, with the parent entity being the Fund, into a corporate structure, with the parent entity being the Corporation. As part of the Conversion and related reorganization transactions, unitholders of the Fund exchanged their trust units for Common Shares of the Corporation on a one-for-one basis, the Fund was dissolved, all of the outstanding Trust Units were cancelled and the Corporation continued as the successor issuer to the Fund. The business, directors and management of the Corporation immediately following completion of the Conversion were the same as the business of the Fund and the directors and management of the Fund (through its administrator, EnerMark Inc.) immediately before completion of the Conversion. As a result of the Conversion, the Corporation became a reporting issuer in each of the provinces and territories of Canada.

SALE OF NON-CORE MARCELLUS ACREAGE

In 2011, the Corporation sold approximately 45% of its total Marcellus acreage, consisting of non-core and primarily non-operated acreage in Pennsylvania, Maryland and West Virginia, for approximately $568 million. The Corporation retained approximately 110,000 net acres in the Marcellus shale natural gas play, of which 60% is operated. The sale included approximately 5.4 MMcfGE/day of natural gas production and approximately 23.4 BcfGE of proved plus probable reserves. Proceeds from the sale were used to reduce outstanding debt under the Bank Credit Facility.

Developments in 2012

FINANCINGS AND MONETIZATION ACTIVITIES

On February 8, 2012, the Corporation completed a bought-deal public offering of 14,708,500 Common Shares for aggregate net proceeds of approximately $331 million. The Corporation initially used the net proceeds of this offering to reduce its outstanding indebtedness under the Bank Credit Facility and subsequently utilized such proceeds to fund a portion of its capital expenditure program in 2012.

On May 15, 2012, the Corporation completed a private placement offering of senior unsecured notes in an aggregate principal amount of approximately US$405 million, issued in three tranches, with terms ranging from seven to 12 years and with interest rates of approximately 4.40%. The Corporation used the net proceeds of this offering to reduce its outstanding indebtedness under the Bank Credit Facility. See "*Description of Capital Structure – Senior Unsecured Notes*".

In August 2012, the Corporation sold all of its common shares in Laricina for net after tax proceeds of approximately $141 million. The net proceeds were used to reduce the Corporation's outstanding indebtedness and subsequently used to fund a portion of its 2012 capital expenditure program. See "*Business of the Corporation – Equity Investments*".

ACQUISITION OF BAKKEN OIL ASSETS IN MONTANA

On December 17, 2012, the Corporation completed an acquisition of an additional 20% working interest in the Sleeping Giant area in the Elm Coulee field in Richland County in Montana for approximately $118 million, including estimated closing adjustments. This acquisition included approximately 1,550 BOE/day of production and was complementary to the Corporation's existing operations in the Sleeping Giant area. This acquisition consolidated the Corporation's working interest in the subject leases to approximately 90%. For a description of the Corporation's Bakken interests, see "*Business of the Corporation – Description of Properties – U.S. Crude Oil Properties".*

SALE OF NON-CORE MANITOBA ASSETS

On December 19, 2012, the Corporation completed a sale of its crude oil assets located in the Virden/Daly region of Manitoba for approximately $218 million, including estimated closing adjustments. This disposition included approximately 1,600 BOE/day of crude oil production. A portion of the proceeds from the sale were used to fund the acquisition of the Corporation's additional working interest in Bakken oil assets in Montana described above, with the balance utilized to reduce indebtedness under the Bank Credit Facility.

Developments in 2013

ACQUISITION OF ADDITIONAL ASSETS

Property and land acquisitions in 2013 totaled $244.8 million, the most significant consisting of additional interest in the Corporation's core Marcellus properties for $157.9 million in the United States and $34.0 million for additional interest in the Pouce Coupe waterflood property in Canada. See "*Business of the Corporation – Description of Properties*".

SALE OF NON-CORE ASSETS

In 2013, the Corporation realized proceeds of approximately $365.1 million from disposition activities involving the Corporation's non-core assets located in Canada and the United States. These dispositions included in aggregate approximately 2,700 BOE/day of production. The proceeds from the Corporation's disposition activities were used to fund the Corporation's capital program and to reduce indebtedness under the Bank Credit Facility.

SUCCESSION OF PRESIDENT & CHIEF EXECUTIVE OFFICER

Mr. Gordon J. Kerr, the former President & Chief Executive Officer of the Corporation, retired effective June 30, 2013 as an officer and director of the Corporation. Mr. Ian C. Dundas succeeded Mr. Kerr as the President & Chief Executive Officer and director of the Corporation effective July 1, 2013. Prior thereto, Mr. Dundas held the position of the Executive Vice President & Chief Operating Officer of the Corporation. See "*Directors and Officers*".

Business of the Corporation

OVERVIEW

In 2013, the Corporation executed on its operational programs delivering production growth and funds flow growth, while maintaining capital discipline and a strong balance sheet. The Corporation's 2013 capital spending was focused on its four core areas (as described below), with a 70% weighting to oil projects. Within the United States, the Corporation's capital program focused on the development of its crude oil and natural gas core areas of operation, which includes its North Dakota and Montana crude oil assets in the Williston Basin, and its natural gas interests in northeast Pennsylvania. Capital spending in the United States was approximately 58% of total capital spending in 2013. Capital spending in Canada was directed to its Canadian crude oil waterflood assets, as well as the on-going delineation of its natural gas assets in the Canadian Deep Basin in northwest Alberta.

In addition to capital spending on development and delineation within its core areas, the Corporation continued to concentrate its portfolio through acquisition and divestment activities. In early 2013, the Corporation acquired an incremental 50% working interest in the Pouce Coupe South Boundary Lake waterflood property, increasing the Corporation's interests in this property to approximately 100%. In late 2013, the Corporation also acquired additional working interests in the Marcellus region, bringing its total Marcellus acreage to approximately 60,000 net non-operated acres at December 31, 2013. During 2013, the Corporation also sold certain non-core assets with 2,700 BOE/day of production in Canada and the United States. The Corporation also sold its undeveloped land in the Montney formation in northeast British Columbia in December 2013, with one-half of the proceeds received in January 2014.

The Corporation's oil and natural gas property interests are located in western Canada in the provinces of Alberta, British Columbia and Saskatchewan, and in the United States, primarily in the states of Montana, North Dakota, Pennsylvania, West Virginia and Wyoming. The Corporation's major producing properties generally have related field production facilities and infrastructure to accommodate its production. In general, sales gas infrastructure for the Marcellus region, specifically in northeastern Pennsylvania, is operating at or near capacity. However, infrastructure projects are underway in the region to address these issues, with most projects to be completed by the end of 2017. See "*Risk Factors – A decline in the Corporation's ability to market oil and natural gas production could have a material adverse effect on its production levels or on the price that the Corporations receives for production*".

Production volumes for the year ended December 31, 2013 from the Corporation's properties consisted of approximately 46% crude oil and NGLs and 54% natural gas, on a BOE basis. The Corporation's 2013 average daily production was 89,793 BOE/day, comprised of 38,250 bbls/day of crude oil, 3,472 bbls/day of NGLs and 288,422 Mcf/day of natural gas, an increase of approximately 9% compared to 2012 average daily production of 82,098 BOE/day, comprised of 36,509 bbls/day of crude oil, 3,627 bbls/day of NGLs and 251,773 Mcf/day of natural gas. The increase in average daily production during 2013 is largely attributable to growth in crude oil production volumes from the Corporation's Fort Berthold properties, as well as increased natural gas production volumes from the Marcellus. The Corporation exited 2013 with average daily production of approximately 99,569 BOE/day in December. Approximately 56% of the Corporation's 2013 production was from Canada, with the remaining 44% from the United States. 67% of its 2013 production was operated by the Corporation; 33% was operated by industry partners.

As at December 31, 2013, the oil and natural gas property interests held by the Corporation were estimated to contain proved plus probable gross reserves of 150,029 Mbbls of light and medium crude oil, 42,066 Mbbls of heavy crude oil, 14,361 Mbbls of NGLs, 564,725 MMcf of natural gas and 600,861 MMcf of shale gas, for a total of 400,720 MBOE. The Corporation's proved reserves represented approximately 65% of total proved plus probable reserves, and approximately 52% of the Corporation's proved plus probable reserves were weighted to crude oil and NGLs. See "*Oil and Natural Gas Reserves*".

Unless otherwise noted, (i) all production and operational information in this Annual Information Form is presented as at or, where applicable, for the year ended, December 31, 2013, (ii) all production information represents the Corporation's company interest in production from these properties, which includes overriding royalty interests of the Corporation but is calculated before deduction of royalty interests owned by others, and (iii) all references to reserve volumes represent gross reserves using forecast prices and costs. See "*Presentation of Oil and Gas Reserves, Resources and Production Information*".

SUMMARY OF PRINCIPAL PRODUCTION LOCATIONS

During the year ended December 31, 2013, on a BOE basis, approximately 56% of the Corporation's production was derived from Canada (40% from Alberta, 12% from Saskatchewan, and 4% from British Columbia) and approximately 44% from the United States (18% from North Dakota, 18% from Pennsylvania, 8% from Montana, less than 1% from Wyoming and minimal amounts from West Virginia). The following table describes the average daily production from the Corporation's principal producing properties and regions during the year ended December 31, 2013.

2013 Average Daily Production from Principal Properties and Regions

	Products					
	Crude Oil					
Property/Region	Light and Medium	Heavy	NGLs	Natural Gas	Shale Gas	Total
	(bbls/day)	(bbls/day)	(bbls/day)	(Mcf/day)	(Mcf/day)	(BOE/day)
United States						
Fort Berthold, North Dakota	15,051		643	4,899		16,511
Marcellus, Pennsylvania					95,273	15,879
Sleeping Giant, Montana	5,336	–	1	10,168	–	7,031
Jonah, Wyoming(1)	1	–	27	2,207	–	396
Total United States	20,388	–	671	17,274	95,273	39,817
Canada						
Medicine Hat Glauconitic "C" Unit, Alberta	–	3,926	–	224	–	3,963
Shackleton, Saskatchewan	–	–	–	22,065	–	3,677
Tommy Lakes, British Columbia	15	–	418	16,641	–	3,207
Brooks, Alberta	–	1,929	32	7,447	–	3,202
Hanlan-Robb, Alberta	–	–	28	18,352	–	3,087
Freda Lake, Saskatchewan	2,060	–	–	–	–	2,060
Bantry, Alberta	1	–	–	11,867	–	1,979
Pembina 5 Way, Alberta	1,304	–	80	1,350	–	1,609
Giltedge, Alberta	–	1,517	–	104	–	1,535
Neptune, Saskatchewan	1,455	–	–	–	–	1,455
Verger, Alberta	–	–	1	7,305	–	1,218
Pine Creek, Alberta	9	–	263	5,513	–	1,191
Elmworth, Alberta	–	–	305	4,893	–	1,120
Hanna Garden, Alberta	–	–	1	6,590	–	1,099
Joarcam, Alberta	692	–	31	2,164	–	1,085
Pouce Coupe, Alberta	419	–	62	3,222	–	1,018
Ansell, Alberta	–	–	85	5,187	–	949
Other Canada	3,371	1,164	1,495	62,952	–	16,522
Total Canada	9,326	8,536	2,801	175,876	–	49,976
Total	29,714	8,536	3,472	193,150	95,273	89,793

Note:

(1) Sold on January 14, 2014.

For additional information on the Corporation's oil and natural gas properties, see "*Description of Properties*".

CAPITAL EXPENDITURES AND COSTS INCURRED

In 2013, the Corporation invested approximately $681 million through its capital program, which was approximately 20% lower than the $853 million in 2012. The Corporation continued to focus the majority of its spending on its core assets, including $315 million on the Fort

Berthold crude oil property, $79 million on Marcellus assets, $165 million on Canadian crude oil properties and $89 million on liquids rich deep gas properties in Canada. The foregoing does not include approximately $245 million of expenditures made on property and land acquisitions in 2013, which includes $158 million in the United States and $34 million for additional interest in our Pouce Coupe waterflood property in Canada.

In the financial year ended December 31, 2013, the Corporation made the following expenditures in the categories noted, as prescribed by NI 51-101:

	Property Acquisition Costs		Exploration	Development
	Proved	Unproved	Costs	Costs
	($ in millions)			
Canada	$ 34.6	$ 9.7	$ 27.3	$ 259.2
United States	131.7	68.8	4.5	390.4
Total	$ 166.3	$ 78.5	$ 31.8	$ 649.6

The Corporation expects its 2014 exploration and development capital spending to be approximately $760 million, with over 60% projected to be invested in crude oil projects. The Corporation expects to invest approximately $300 million to $325 million of capital on its Fort Berthold property in the United States, representing approximately 40% of its planned 2014 capital spending. The Corporation intends to finance its 2014 capital expenditure program through a combination of internally-generated cash flow, debt, divestments and proceeds from its stock dividend program. The Corporation will review its 2014 capital investment plans regularly throughout the year in the context of prevailing economic conditions and potential acquisitions, and make adjustments as it deems necessary.

For additional information regarding the Corporation's planned 2014 development capital expenditures for its properties, see "– *Description of Properties*" below.

EXPLORATION AND DEVELOPMENT ACTIVITIES

The following table summarizes the number and type of wells that the Corporation drilled or participated in the drilling of for the year ended December 31, 2013, in each of Canada and the United States. Wells have been classified in accordance with the definitions of such terms in NI 51-101.

	Canada				United States			
	Development Wells		Exploratory Wells		Development Wells		Exploratory Wells	
Category of Well	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Crude oil wells	62	23	2	–	80	20	–	–
Natural gas wells	14	8	5	2	97	9	–	–
Service wells	30	9	–	–	–	–	–	–
Dry and abandoned wells	–	–	–	–	–	–	–	–
Total	106	40	7	2	177	29	–	–

For a description of the Corporation's planned 2014 development plans and the anticipated sources of funding those plans, see " – *Capital Expenditures and Costs Incurred*" above and "– *Description of Properties*" below.

OIL AND NATURAL GAS WELLS AND UNPROVED PROPERTIES

The following table summarizes, as at December 31, 2013, the Corporation's interests in producing wells and in non-producing wells which were not producing but which may be capable of production, along with the Corporation's interests in unproved properties (as defined in NI 51-101). Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the proportion of oil or natural gas production that constitutes the majority of production from that well.

	Producing Wells				Non-Producing Wells				Unproved Properties (acres)	
	Oil		Natural Gas		Oil		Natural Gas			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada										
Alberta	1,584	860	6,319	3,367	609	283	764	259	681,888	319,474
Saskatchewan	841	159	2,294	2,166	288	40	207	186	316,369	295,420
British Columbia	–	–	241	158	1	–	42	19	80,187	41,999
Ontario									32,882	–
United States										
Montana	256	182	1	1	3	1	–	–	2,430	2,430
North Dakota	228	99	–	–	39	8	–	–	3,254	3,254
Pennsylvania	–	–	508	53	–	–	147	16	149,867	49,984
West Virginia	–	–	1	1	–	–	2	2	26,948	26,948
Maryland									286	286
Total	**2,909**	**1,300**	**9,364**	**5,746**	**940**	**332**	**1,162**	**482**	**1,294,111**	**739,795**

The Corporation expects its rights to explore, develop and exploit on approximately 14,000 net acres of unproved properties in Canada and the United States to expire prior to December 31, 2014 in the ordinary course. The Corporation has no material work commitments on such properties and, where the Corporation determines appropriate, it can extend expiring leases by either making the necessary applications to extend or performing the necessary work.

DESCRIPTION OF PROPERTIES

Outlined below is a description of the Corporation's Canadian and U.S. crude oil and natural gas properties and assets.

Canadian Crude Oil Properties

OVERVIEW

The Corporation's Canadian crude oil production represents approximately 47% of its total crude oil production. This production comes primarily from low decline properties under waterflood, which provide the Corporation with a stable production base and generate free cash flow to support investment in the Corporation's growth plays, as well as its dividend. In a waterflood, water is injected into the formation to supplement the original reservoir pressure and provide a drive mechanism to move additional oil to producing wells. Pressure maintenance and the production of oil from water injection can result in a production profile with more predictable and stable declines and higher recovery of reserves. Infill drilling and well/injector optimization are effective methods of improving reserve recovery even further. These properties have associated crude oil production installations for emulsion treatment and injection or water disposal. The Canadian crude oil portfolio includes a variety of properties producing from the Cardium, Viking, Boundary Lake, Ratcliffe, Sparky/Lloydminster, Lower Mannville and Glauconitic formations. The Corporation operated over 92% of its Canadian crude oil producing assets as at December 31, 2013.

In 2013, the Corporation's five largest crude oil producing properties were Medicine Hat, Brooks, Freda Lake, Pembina 5 Way and Giltedge, all of which are located in Alberta with the exception of Freda Lake, which is located in Saskatchewan. Production from the Canadian crude oil assets averaged 17,862 BOE/day in 2013, representing approximately 20% of the Corporation's total production for the year. A total of 89.8 MMBOE of proved plus probable reserves were associated with these assets at December 31, 2013, representing 22% of the Corporation's total proved plus probable reserves.

In 2013, the Corporation invested approximately $165 million on its Canadian crude oil assets with approximately 53% directed to drilling and completions and the remainder on plant and facility enhancements to support future activities. The Corporation drilled 21.1 net crude oil wells in Canada in 2013, with the majority of the drilling in the Ratcliffe, Cardium and Glauconitic formations. In addition, the Corporation advanced work on two enhanced oil recovery ("**EOR**") projects at Medicine Hat and Giltedge.

The Corporation plans to spend approximately $160 million to $200 million on its Canadian crude oil assets in 2014, focusing at Freda Lake in Saskatchewan and Medicine Hat, Giltedge, Brooks and Pembina in Alberta.

CONTINGENT RESOURCE ESTIMATE

The Corporation has conducted an internal evaluation of the contingent resources associated with a portion of its crude oil waterflood properties which has resulted in a "best estimate" of 58.9 MMBOE being classified as economic contingent resources effective as of December 31, 2013. These contingent resources are economic based on the price and cost assumptions used in the Corporation's 2013 year end reserves evaluations. Improved oil recovery ("**IOR**") from twelve existing waterfloods through optimization work accounts for approximately 25.7 MMBOE of the total. Approximately 33.2 MMBOE of the total is attributable to EOR projects in the Corporation's Giltedge property and the Medicine Hat Glauconitic "C" Unit where projects are underway. As work proceeds and assessed results continue to support the economic viability of these projects, the Corporation expects that contingent resources will be reclassified as reserves. Although further EOR projects are being contemplated on certain of the Corporation's other Canadian crude oil properties, these have not been fully evaluated and no contingent resource has been assessed. There is no certainty that it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources". Significant positive factors embedded in this estimate include well-established waterflood technology and a long history of waterflood performance data. The EOR estimates are based on incremental recovery from higher displacement efficiency without any improvement in areal sweep. A significant negative factor relevant to this estimate is the geological complexity and its effect on injector producer connectivity. The contingency preventing these resources from being classified as reserves is the early stage of implementation to the specific waterfloods. There are a number of inherent risks and contingencies associated with the development of these properties including the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in this Annual Information Form.

For additional information on the disclosure of contingent resources, including with respect to the presentation of the "best estimate" of contingent resources, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Disclosure of Contingent Resources*".

Canadian Natural Gas Properties

OVERVIEW

The Corporation's Canadian natural gas properties are located in Alberta, Saskatchewan and British Columbia. Its primary focus area is within the Deep Basin region where the Corporation holds over 161,000 net acres of high working interest lands. These lands include approximately 76,000 net acres targeting the Stacked Mannville zones (59,000 of which are in the Wilrich formation) and 85,000 net acres in the Willesden Green region of Alberta, targeting the liquids rich Duvernay formation. The Corporation has additional natural gas properties producing from the Nikannassin and Bluesky formations, as well as shallow gas producing assets at Shackleton, in southwest Saskatchewan, and Bantry, Verger, Hanna Garden and Medicine Hat South in Alberta. In 2013, the Corporation directed its capital spending program on the Wilrich and Duvernay formations that it believes provides stronger economic returns than those provided by shallow gas assets or other conventional natural gas assets within its portfolio.

The Corporation invested $84 million in its Canadian natural gas assets in the Deep Basin in 2013. The Corporation continued to delineate its Wilrich position in the Edson and Ansell Minehead areas of Alberta, drilling four wells and bringing three Wilrich wells on-stream during 2013. The Corporation also drilled two vertical Duvernay test wells during 2013 and one horizontal re-entry into a vertical test well. The core analysis from the test wells continues to confirm a range of free condensate across a significant portion of the Corporation's acreage. Further delineation drilling and completions are planned by the Corporation in 2014 to better understand productivity of natural gas and NGLs in this area.

The Corporation's Canadian natural gas production averaged 175,876 Mcf/day in 2013 (exiting 2013 at 161,965 Mcf/day). Proved plus probable reserves totalled 478 BcfGE at December 31, 2013, representing approximately 20% of the Corporation's proved plus probable reserves measured on a BOE basis. The Corporation's largest producing Canadian natural gas properties in 2013 were its Shackleton property in Saskatchewan, its Tommy Lakes property in northern British Columbia and Ansell, Bantry and Verger, all of which are located in Alberta.

The Corporation plans to invest approximately $84 million on both its operated and non-operated liquids-rich deep natural gas assets in 2014. The Corporation intends to continue to delineate the Wilrich formation in the Edson, Ansell, Minehead and Hanlon areas and will also continue its delineation of the Duvernay formation.

CONTINGENT RESOURCE ESTIMATE

The Corporation has conducted an internal evaluation of the contingent resources associated with a portion of Canadian natural gas assets targeting the Wilrich formation. This assessment has resulted in a "best estimate" of 253 BcfGE of economic contingent resources effective as of December 31, 2013. This internal estimate has been audited by McDaniel. The development of these resources is contingent on confirmation of commercial productivity of the undrilled reserves locations and subsequent internal development project approval. The classification of the resources in the Wilrich formation as contingent resources is based on the productivity of the Wilrich formation being similar to the Corporation's adjacent Wilrich producing reserves and offset productivity of competitor wells. These contingent resources have been geologically mapped with significant control from wells drilled for deeper horizons and are economic based on the price and cost assumptions used in the Corporation's 2013 year end reserves evaluations. Significant factors embedded in this estimate include an average recovery of five Bcf per well with ultimate recovery of 50% of the estimated original natural gas in place. There is no certainty that it will be commercially viable to produce, or that the Corporation will produce any portion of the volumes currently classified as "contingent resources". There are a number of inherent risks and contingencies associated with the development of these properties including the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above and under "*Risk Factors*" in this Annual Information Form.

U.S. Crude Oil Properties

OVERVIEW

The Corporation's U.S. crude oil properties are located primarily in the Fort Berthold region of North Dakota and in Richland County, Montana. The Corporation has an approximate 90% average working interest in Fort Berthold with 73,000 net acres of land located primarily in Dunn and McKenzie counties. Production from the Fort Berthold region is from the Bakken and Three Forks formations and consists of light sweet crude oil (42° API) and some associated natural gas and natural gas liquids. Fort Berthold production increased from 14,023 BOE/day at the end of 2012 to approximately 18,000 BOE/day at exit 2013. The Corporation added approximately 25.6 MMBOE of proved plus probable reserves at Fort Berthold field during 2013 for a total of 105.4 MMBOE of proved plus probable reserves associated with this property. The Corporation owns a 90% working interest in the Sleeping Giant property located in the Elm Coulee field in Richland County, Montana. Sleeping Giant is a mature, light oil property which produced 7,031 BOE/day on average in 2013 from the Bakken formation with an average decline of 14%. The Corporation believes there is additional upside potential at Sleeping Giant property through production optimization, refracs, limited infill drilling and the potential for enhanced oil recovery.

Overall, the Corporation's U.S. crude oil and natural gas liquids production averaged approximately 21,059 BOE/day in 2013, representing 50% of the Corporation's 2013 average daily crude oil and liquids production on a BOE basis. The Corporation had 131.2 MMBOE of proved plus probable reserves associated with these assets at December 31, 2013, representing 33% of its total proved plus probable reserves.

The Corporation spent approximately $316 million of capital on its U.S. crude oil assets in 2013, including approximately $315 million at its Fort Berthold property, representing the single largest capital investment in the Corporation's portfolio. In 2013, there were 20.3 net horizontal wells drilled in the Fort Berthold region, targeting both the Bakken and Three Forks formations (consisting of 0.9 short lateral wells and 19.4 long lateral wells) with approximately 24.7 net wells brought on stream during 2013.

In 2014, the Corporation expects to spend between $300 million and $325 million, representing approximately 40% to 43% of its capital budget, on its U.S. crude oil assets with over 95% targeted for the Fort Berthold area. The Corporation plans to drill 20 to 25 net horizontal wells in this region in 2014 with of the majority of these wells planned as long lateral horizontal wells.

CONTINGENT RESOURCE ESTIMATE

An evaluation of the Corporation's interests in the Bakken and Three Forks formations at Fort Berthold, North Dakota conducted internally by the Corporation and audited by McDaniel has attributed a "best estimate" of 38.5 MMBOE of economic contingent resources attributable to these formations, effective as of December 31, 2013. As described above, the Corporation converted 7.4 MMBOE of Bakken and 10.6 MMBOE of Three Forks contingent resources into reserves during the year, and added 16.8 MMBOE and 6.2 MMBOE of contingent resources attributable to the Three Forks formation and the Bakken formation, respectively, at December 31, 2013. These contingent resources represent 47.2 net future drilling locations over and above 98 net booked drilling locations identified in the Corporation's booked proved plus probable reserves. These estimates are based primarily upon a drilling density of two wells per drilling spacing unit in each of the Bakken and Three Forks formations. The average expected ultimate recovery per well is estimated at 815 MBOE in this region. These contingent resources are economic using established technologies and under current commodity prices. Given the drilling density to date, the Corporation assumed a non-reserve land utilization of 84% for the Bakken and 92% for the Three Forks formations. The Corporation has approximately 99 net wells currently on production in this area. For additional information on the disclosure of contingent resources, including with respect to the presentation of the "best estimate" of contingent resources, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Disclosure of Contingent Resources*".

There is no certainty that it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources". The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with the Fort Berthold, North Dakota properties as reserves consist of additional delineation drilling to confirm economic productivity in the undeveloped areas and limitations to development based on adverse topography or other surface restrictions. Significant positive factors related to the estimate include continued advancement of drilling and completion technology and performance of producing wells continues at expected levels. A significant factor related to the estimate is the limited long-term performance history in the immediate area of the contingent resource. There are a number of inherent risks and contingencies associated with the development of the interests in the property including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on industry partners in project development, funding and provisions of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in this Annual Information Form.

U.S. Natural Gas Properties

The Corporation's U.S. natural gas properties primarily consist of its non-operated Marcellus shale gas interests located in northeastern Pennsylvania where the Corporation holds an interest in approximately 60,000 net acres. The Corporation also holds 23,000 net non-core operated acres in West Virginia and Maryland.

The Corporation's U.S. natural gas production averaged 112,547 Mcf/day in 2013, representing approximately 39% of the Corporation's total natural gas production. As a result of the acquisition of additional working interests in northeastern Pennsylvania during the fourth quarter of 2013, exit production from the Marcellus was approximately 171,083 Mcf/day. Proved plus probable U.S. natural gas reserves were 600.9 Bcf as at December 31, 2013, an increase of 168% from year-end 2012 and represented 25% of the Corporation's total proved plus probable reserves.

In 2013, $79 million was invested in the Corporation's interests in the Marcellus. The Corporation participated in the drilling of a total of approximately 9.3 net wells and a total of approximately 12.7 net wells were brought on stream. The Corporation currently has 54.1 net producing wells in the Marcellus, and 13.3 net wells waiting on completions or tie-in.

The Corporation plans to spend between $110 million and $130 million on drilling projects in its Marcellus properties in the northeast region of Pennsylvania in 2014. The Corporation expects its Marcellus production to grow from 95 MMcf/day in 2013 to over 140 MMcf/day in 2014, which would represent approximately 40% of the Corporation's anticipated natural gas production.

The Corporation has entered into long-term agreements for the gathering, dehydration, processing, compression and transportation of the Corporation's share of production from its Marcellus properties. These agreements are intended to provide the Corporation with cost certainty and direct ties to the northeastern United States natural gas markets through connections with major interstate pipelines.

CONTINGENT RESOURCE ESTIMATE

NSAI has also conducted an independent assessment of the contingent resources attributable to the Corporation's interests in the Marcellus properties and has provided a "best estimate" of economic natural gas contingent resources of approximately 1.3 Tcf at December 31, 2013. Approximately 258 Bcf of contingent resources were reclassified as reserves in 2013. However, as a result of reduced estimates of expected ultimate recoveries, the contingent resource estimate was reduced in certain areas and eliminated in others where current economics do not support further development or lease extension of the acreage. The Corporation did see an increase in the contingent resource estimate assigned to its non-operated leases in northeast Pennsylvania due to improved performance. The remaining contingent resources are economic based on the forecast price and cost assumptions used for the Corporation's year-end 2013 reserves evaluations. This estimate assumes a land utilization rate of 65% and that the average well would produce approximately 6.6 Bcf.

There is no certainty that it will be commercially viable to produce, or that the Corporation will produce, any portion of the volumes currently classified as "contingent resources". The primary contingencies which currently prevent the classification of the Corporation's disclosed contingent resources associated with its Marcellus interests as reserves consist of additional delineation drilling to confirm economic productivity in the immediate vicinity of the development areas, limitations to development based on adverse topography or other surface restrictions, the uncertainty regarding marketing and transportation of natural gas from development areas, the receipt of all required regulatory permits and approvals to develop the land, and limited access to confidential information of other operators in the Marcellus formation that would support the recognition of reserves on the Corporation's areas of interest. Significant negative factors related to the estimate include: the pace of development, including drilling and infrastructure, is slower than the forecast, risk of adverse regulatory and tax changes, and other issues related to gas development in populated areas. There are a number of inherent risks and contingencies associated with the development of the Corporation's interests in the Marcellus properties including commodity price fluctuations, project costs, the Corporation's ability to make the necessary capital expenditures to develop the properties, reliance on the Corporation's industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above and that apply generally to oil and gas operations as described above and under "*Risk Factors*" in this Annual Information Form.

For additional information on the disclosure of contingent resources, including with respect to the presentation of the "best estimate" of contingent resources, see "*Presentation of Oil and Gas Reserves, Resources and Production Information – Disclosure of Contingent Resources*".

QUARTERLY PRODUCTION HISTORY

The following table sets forth the Corporation's average daily production volumes, on a company interest basis, for each fiscal quarter in 2013 and for the entire year, separately for production in Canada and the United States, and in total.

	Year Ended December 31, 2013				
Country and Product Type	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Light and medium oil (bbls/day)	10,019	9,670	9,230	8,406	**9,326**
Heavy oil (bbls/day)	9,150	8,694	8,016	8,297	**8,536**
Total crude oil (bbls/day)	19,169	18,364	17,246	16,703	**17,862**
Natural gas liquids (bbls/day)	3,116	2,975	2,265	2,858	**2,801**
Total liquids (bbls/day)	22,285	21,339	19,511	19,561	**20,663**
Natural gas (Mcf/day)	177,809	186,569	174,169	165,114	**175,876**
Total Canada (BOE/day)	51,919	52,434	48,539	47,080	**49,976**
United States					
Light and medium oil (bbls/day)	19,152	19,702	21,637	21,028	**20,388**
Natural gas liquids (bbls/day)	479	522	720	955	**671**
Total liquids (bbls/day)	19,631	20,224	22,357	21,983	**21,059**
Natural gas (Mcf/day)	15,113	16,260	17,627	20,033	**17,274**
Shale gas (Mcf/day)	78,680	88,012	83,368	130,592	**95,273**
Total United States (BOE/day)	35,264	37,603	39,190	47,087	**39,817**
Total					
Light and medium oil (bbls/day)	29,171	29,372	30,867	29,434	**29,714**
Heavy oil (bbls/day)	9,150	8,694	8,016	8,297	**8,536**
Total crude oil (bbls/day)	38,321	38,066	38,883	37,731	**38,250**
Natural gas liquids (bbls/day)	3,595	3,497	2,985	3,813	**3,472**
Total liquids (bbls/day)	41,916	41,563	41,868	41,544	**41,722**
Natural gas (Mcf/day)	192,922	202,829	191,796	185,147	**193,150**
Shale gas (Mcf/day)	78,680	88,012	83,368	130,592	**95,273**
Total (BOE/day)	87,183	90,037	87,729	94,167	**89,793**

QUARTERLY NETBACK HISTORY

The following tables set forth the Corporation's average netbacks received for each fiscal quarter in 2013 and for the entire year, separately for production in Canada and the United States, and in total. Netbacks are calculated on the basis of prices received before the effects of commodity derivative instruments but after transportation costs, less related royalties and related production costs. For multiple product well types, production costs are entirely attributed to that well's principal product type. As a result, no production costs are attributed to the Corporation's NGLs production as those costs have been attributed to the applicable wells' principal product type.

	Year Ended December 31, 2013				
Light and Medium Crude Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada					
Sales price[1]	$ 81.47	$ 84.31	$ 97.82	$ 78.22	**$ 85.55**
Royalties[2]	(12.77)	(13.73)	(17.09)	(14.07)	**(14.39)**
Production costs[3]	(24.22)	(21.85)	(21.30)	(22.69)	**(22.53)**
Netback	$ 44.48	$ 48.73	$ 59.43	$ 41.46	**$ 48.63**
United States					
Sales price[1]	$ 89.06	$ 86.58	$ 98.04	$ 83.89	**$ 89.52**
Royalties[2]	(24.15)	(23.42)	(27.80)	(23.43)	**(24.76)**
Production costs[3]	(7.02)	(9.23)	(9.16)	(8.92)	**(8.62)**
Netback	$ 57.89	$ 53.93	$ 61.08	$ 51.54	**$ 56.14**
Total					
Sales price[1]	$ 86.45	$ 85.83	$ 97.98	$ 82.27	**$ 88.27**
Royalties[2]	(20.24)	(20.23)	(24.60)	(20.76)	**(21.51)**
Production costs[3]	(12.93)	(13.39)	(12.79)	(12.85)	**(12.98)**
Netback	$ 53.28	$ 52.21	$ 60.59	$ 48.66	**$ 53.78**

	Year Ended December 31, 2013				
Heavy Oil ($ per bbl)	**First Quarter**	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Annual**
Canada/Total					
Sales price[1]	$ 53.24	$ 73.22	$ 89.86	$ 61.78	**$ 69.07**
Royalties[2]	(10.54)	(15.38)	(18.87)	(13.28)	**(14.41)**
Production costs[3]	(11.66)	(16.26)	(16.47)	(18.24)	**(15.58)**
Netback	$ 31.04	$ 41.58	$ 54.52	$ 30.26	**$ 39.08**

Natural Gas Liquids ($ per bbl)	Year Ended December 31, 2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Canada					
Sales price(1)	$ 62.33	$ 49.05	$ 58.64	$ 52.39	**$ 55.51**
Royalties(2)	(16.79)	(13.96)	(16.50)	(15.11)	**(15.55)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 45.54	$ 35.09	$ 42.14	$ 37.28	**$ 39.96**
United States					
Sales price(1)	$ 34.22	$ 26.21	$ 22.31	$ 59.87	**$ 38.64**
Royalties(2)	(8.53)	(6.57)	(6.58)	(8.35)	**(7.56)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 25.69	$ 19.64	$ 15.73	$ 51.52	**$ 31.08**
Total					
Sales price(1)	$ 58.58	$ 45.64	$ 49.88	$ 54.26	**$ 52.25**
Royalties(2)	(15.69)	(12.86)	(14.11)	(13.42)	**(14.01)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 42.89	$ 32.78	$ 35.77	$ 40.84	**$ 38.24**

Natural Gas ($ per Mcf)	Year Ended December 31, 2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Canada					
Sales price(1)	$ 2.89	$ 3.39	$ 2.62	$ 3.12	**$ 3.01**
Royalties(2)	(0.09)	(0.14)	(0.07)	(0.07)	**(0.09)**
Production costs(3)	(2.17)	(1.87)	(2.01)	(2.33)	**(2.09)**
Netback	$ 0.63	$ 1.38	$ 0.54	$ 0.72	**$ 0.83**
United States					
Sales price(1)	$ 4.89	$ 5.35	$ 5.32	$ 4.40	**$ 4.96**
Royalties(2)	(1.13)	(1.21)	(1.18)	(1.24)	**(1.19)**
Production costs(3)	–	–	–	–	**–**
Netback	$ 3.76	$ 4.14	$ 4.14	$ 3.16	**$ 3.77**
Total					
Sales price(1)	$ 3.04	$ 3.55	$ 2.87	$ 3.26	**$ 3.18**
Royalties(2)	(0.17)	(0.23)	(0.17)	(0.19)	**(0.19)**
Production costs(3)	(2.00)	(1.72)	(1.82)	(2.08)	**(1.90)**
Netback	$ 0.87	$ 1.60	$ 0.88	$ 0.99	**$ 1.09**

Shale Gas ($ per Mcf)	Year Ended December 31, 2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
United States/Total					
Sales price(1)	$ 3.23	$ 4.06	$ 3.18	$ 3.26	**$ 3.42**
Royalties(2)	(0.68)	(0.85)	(0.70)	(0.68)	**(0.73)**
Production costs(3)	(0.57)	(0.68)	(0.70)	(0.61)	**(0.64)**
Netback	$ 1.98	$ 2.53	$ 1.78	$ 1.97	**$ 2.05**

Total ($ per BOE)	Year Ended December 31, 2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
Canada					
Sales price[1]	$ 38.89	$ 42.67	$ 45.69	$ 38.97	**$ 41.56**
Royalties[2]	(5.63)	(6.39)	(7.40)	(6.01)	**(6.35)**
Production costs[3]	(14.15)	(13.38)	(13.97)	(15.43)	**(14.21)**
Netback	$ 19.11	$ 22.90	$ 24.32	$ 17.53	**$ 21.00**
United States					
Sales price[1]	$ 58.14	$ 57.54	$ 63.69	$ 49.60	**$ 56.83**
Royalties[2]	(15.24)	(14.87)	(17.50)	(13.05)	**(15.06)**
Production costs[3]	(5.09)	(6.43)	(6.54)	(5.68)	**(5.94)**
Netback	$ 37.81	$ 36.24	$ 39.65	$ 30.87	**$ 35.83**
Total					
Sales price[1]	$ 46.67	$ 48.65	$ 53.61	$ 43.79	**$ 48.11**
Royalties[2]	(9.52)	(9.93)	(11.91)	(9.53)	**(10.21)**
Production costs[3]	(10.37)	(10.42)	(10.60)	(10.52)	**(10.48)**
Netback	$ 26.78	$ 28.30	$ 31.10	$ 23.74	**$ 27.42**

Notes:

(1) Net of transportation costs but before the effects of commodity derivative instruments.
(2) Includes production taxes.
(3) Production costs are costs incurred to operate and maintain wells and related equipment and facilities, including operating costs of support equipment used in oil and gas activities and other costs of operating and maintaining those wells and related equipment and facilities. Examples of production costs include items such as field staff labour costs, costs of materials, supplies and fuel consumed and supplies utilized in operating the wells and related equipment (such as power (including gains and losses on electricity contracts), chemicals and lease rentals), repairs and maintenance costs, property taxes, insurance costs, costs of workovers, net processing and treating fees, overhead fees, taxes (other than income, capital, withholding or U.S. state production taxes) and other costs.

ABANDONMENT AND RECLAMATION COSTS

In connection with its operations, the Corporation will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. The Corporation budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. The Corporation estimates such costs through a model that incorporates data from the Corporation's operating history, industry sources and cost formulas used by Alberta's Energy Resources Conservation Board, together with other operating assumptions. The Corporation expects all of its net wells to incur these costs. The Corporation anticipates the total amount of such costs, net of estimated salvage value for such equipment, to be approximately $721 million on an undiscounted basis and $158 million discounted at 10% in accordance with NI 51-101. The calculations of future net revenue associated with proved plus probable reserves under *"Oil and Natural Gas Reserves*" in this Annual Information Form exclude approximately $412 million on an undiscounted basis and $66 million discounted at 10% as these amounts represent costs for abandonment and reclamation of facilities and wells for which no reserves have been attributed. In the next three financial years, the Corporation anticipates that a total of approximately $81 million on an undiscounted basis and $69 million discounted at 10% will be incurred in respect of abandonment and reclamation costs.

TAX HORIZON

The Corporation is subject to standard applicable corporate income taxes. Within the context of current commodity prices and capital spending plans, the Corporation generally does not expect to be paying material cash taxes in Canada until after 2018 as it estimates it has sufficient tax pools to offset its anticipated taxable income prior to that time. The Corporation expects to pay U.S. cash taxes of approximately 3% to 5% of U.S. cash flow in 2014 and 2015, which is mainly related to Alternative Minimum Tax ("**AMT**"). AMT is recoverable against regular income taxes payable in the future. These estimates may vary depending on numerous factors, including fluctuations in commodity prices, and the Corporation's capital spending, changes in governing tax laws, and the nature and timing of the Corporation's acquisitions and dispositions. If crude oil and natural gas prices were to strengthen beyond the levels anticipated by the current forward market, the Corporation's tax pools, including the AMT credit, would be utilized more quickly and it may experience higher than expected cash taxes or payment of such taxes in an earlier time period, including regular U.S. income taxes. As a result, the Corporation emphasizes that it is difficult to give guidance on future taxability as it operates within an industry that constantly changes. See "*Risk Factors – Changes in income tax and other laws may adversely affect the Corporation and its shareholders*."

For additional information, see Notes 2(g) and 13 to the Corporation's audited consolidated financial statements for the year ended December 31, 2013 and the information under the heading "*Taxes*" in the Corporation's MD&A for the year ended December 31, 2013.

MARKETING ARRANGEMENTS AND FORWARD CONTRACTS

Crude Oil and NGLs

The Corporation's crude oil and NGLs production is marketed to a diverse portfolio of intermediaries and end users generally on 30-day continuously renewing contracts for crude oil and yearly contracts for NGLs whose terms fluctuate with the monthly spot markets. The Corporation received an average price (net of transportation costs but before the effects of commodity derivative instruments) of $88.27/bbl for its light and medium crude oil, $69.07/bbl for its heavy crude oil and $52.25/bbl for its NGLs for the year ended December 31, 2013, compared to $81.16/bbl for its light and medium crude oil, $68.73/bbl for its heavy crude oil and $53.01/bbl for its NGLs for the year ended December 31, 2012.

In Canada, the Corporation sells its crude oil production generally on a 30-day evergreen basis at floating index-based prices. The Corporation typically transports its Canadian crude oil production to its buyers by pipeline or truck. The Corporation has field gathering transportation agreements in place for 2014 to 2016 for approximately 1,500 bbls/day to 2,400 bbls/day of its Saskatchewan production. The Corporation also has pipeline transportation agreements in place for 2016 to 2025 for an average of approximately 900 bbl/day of its Alberta crude oil production. The Corporation typically sells its NGLs production on a one-year contracted basis at floating index-based prices. The Corporation has also contracted NGLs pipeline transportation agreements for an average of approximately 500 BOE/day through 2018.

In the United States, the Corporation sells its crude oil production generally on a negotiated 30-day basis at floating index-based prices. The Corporation transports its U.S. crude oil production to its buyers by pipeline, truck, and/or rail. The Corporation has pipeline transportation agreements in place for 8,500 bbls/day of its U.S. oil production to mid-2016, falling to 7,500 bbls/day through 2018. The Corporation does not directly market its NGLs associated with its U.S. crude oil production. These volumes are marketed on its behalf by midstream companies in North Dakota and Montana.

Natural Gas

In marketing its natural gas production, the Corporation strives for a mix of contracts and customers. In Canada, the Corporation sells its natural gas production at a mix of fixed and floating prices for a variety of terms ranging from spot sales to one year or longer. The Corporation's monthly sales portfolio reflected a relatively equal balance between the daily and monthly AECO market indices in 2013. Approximately 60% of the Corporation's total natural gas production originated in Canada in 2013 and received an average price of $3.01/Mcf during the year.

Approximately 40% of the Corporation's natural gas production originated in the United States. The Corporation sold approximately 60% of its Marcellus production in 2013 on the Transco Leidy Pipeline, with the remaining volumes sold on the Tennessee Gas Pipeline 300 Line in Pennsylvania. The Corporation has firm "must-take" sales contracts for 65 MMcf/day to 70 MMcf/day of natural gas production in the Marcellus with buyers holding pipeline capacity on either of these pipelines. The Corporation received an average price for its U.S. shale natural gas production of US$3.42/Mcf. Approximately 15% of the Corporation's U.S. natural gas production was associated natural gas production from its crude oil operations in North Dakota and Montana. The Corporation does not market these volumes directly, as they are marketed on our behalf by midstream companies. The Corporation received US$4.96/Mcf for this production in 2013 because of the high heat content of the natural gas due to associated liquids.

The Corporation's percentage of 2013 revenues attributable to natural gas (net of transportation costs but before the effects of commodity derivative instruments) was 22% compared to 16% in 2012. The average price received by the Corporation (net of transportation costs but before the effects of commodity derivative instruments) for its natural gas in 2013 was $3.26/Mcf compared to $2.39/Mcf for the year ended December 31, 2012.

For 2014, the Corporation has contracts for up to approximately 190 MMcf/day of pipeline capacity, some of it in series, for natural gas in Canada and the United States with contracts that range anywhere from one month to five years. This capacity ensures the Corporation's natural gas production is delivered from the field onto major pipelines and enables the Corporation to sell its production to the local marketplace.

Future Commitments and Forward Contracts

The Corporation may use various types of derivative financial instruments and fixed price physical sales contracts to manage the risk related to fluctuating commodity prices. Absent such hedging activities, all of the crude oil and NGLs and the majority of natural gas production of the Corporation is sold into the open market at prevailing market prices, which exposes the Corporation to the risks associated with commodity price fluctuations and foreign exchange rates. See "*Risk Factors*". Information regarding the Corporation's financial instruments is contained in Note 15 to the Corporation's audited consolidated financial statements for the year ended December 31, 2013 and under the headings "*Results of Operations – Pricing*" and "*Results of Operations – Price Risk Management*" in the Corporation's MD&A for the year ended December 31, 2013, each of which is available through the internet on the Corporation's website at www.enerplus.com, on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov.

Oil and Natural Gas Reserves

SUMMARY OF RESERVES

All of the Corporation's reserves, including its U.S. reserves, have been evaluated in accordance with NI 51-101. Independent reserves evaluations have been conducted on properties comprising approximately 89.5% of the Corporation's total proved plus probable reserves value (discounted at 10%, using forecast prices and costs). McDaniel, an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise approximately 74% of the net present value (discounted at 10%, using forecast prices and costs) of the Corporation's proved plus probable reserves located in Canada and all of the Corporation's reserves associated with the Corporation's properties located in North Dakota and Montana. The Corporation has evaluated the balance of its Canadian properties using similar evaluation parameters, including the same forecast price, inflation and exchange rate assumptions utilized by McDaniel. McDaniel has reviewed the Corporation's internal evaluation of these properties.

NSAI, independent petroleum consultants based in Dallas, Texas, has evaluated all of the Corporation's reserves associated with the Corporation's properties in Pennsylvania, West Virginia and Wyoming. For consistency in the Corporation's reserves reporting, NSAI used McDaniel's January 1, 2014 forecast prices and inflation rates to prepare their reports. The Corporation used McDaniel's forecast exchange rates set forth below to convert U.S. dollar amounts in the NSAI Report to Canadian dollar amounts for presentation in this Annual Information Form.

The following sections and tables summarize, as at December 31, 2013, the Corporation's oil, NGLs, natural gas and shale gas reserves and the estimated net present values of future net revenues associated with such reserves, together with certain information, estimates and assumptions associated with such reserve estimates. The data contained in the tables is a summary of the evaluations, and as a result the tables may contain slightly different numbers than the evaluations themselves due to rounding. Additionally, the columns and rows in the tables may not add due to rounding. For information relating to the changes in the volumes of the Corporation's reserves from December 31, 2012 to December 31, 2013, see "– *Reconciliation of Reserves*" below.

All estimates of future net revenues are stated prior to provision for interest and general and administrative expenses and after deduction of royalties and estimated future capital expenditures, and are presented both before and after deducting income taxes. For additional information, see "*Business of the Corporation – Tax Horizon*", "*Industry Conditions*" and "*Risk Factors*" in this Annual Information Form.

With respect to pricing information in the following reserves information, the wellhead oil prices were adjusted for quality and transportation based on historical actual prices. The natural gas prices were adjusted, where necessary, based on historical pricing based on heating values and the differing costs of service applied by various purchasers. The NGLs prices were adjusted to reflect historical average prices received.

It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of the Corporation's crude oil, NGLs and natural gas reserves provided herein are estimates only. Actual reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Presentation of Oil and Gas Reserves, Resources and Production Information*" in conjunction with the following tables and notes.

The following tables set forth the estimated gross and net reserves volumes and net present value of future net revenue attributable to the Corporation's reserves at December 31, 2013, using forecast price and cost cases. The Corporation has also previously publicly disclosed its reserves on a "company interest" basis (being the gross volumes plus the Corporation's share of royalty interests in reserves), which results in an additional 5.3 MMBOE of proved plus probable reserves attributed to the Corporation. "Company interest" is not a term defined in NI 51-101 and therefore may not be comparable to reserves estimates disclosed by other issuers in accordance with NI 51-101.

Summary of Oil and Gas Reserves (Forecast Prices and Costs)
As of December 31, 2013

	Oil and Natural Gas Reserves											
	Light & Medium Oil		Heavy Oil		Natural Gas Liquids		Natural Gas		Shale Gas		Total	
Reserves Category	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)
Proved Developed Producing												
Canada	23,145	20,400	26,689	21,407	5,737	4,200	293,384	262,389	–	–	104,468	89,738
United States	40,861	33,204	–	–	1,429	1,198	45,262	42,718	212,770	170,423	85,296	69,925
Total	**64,006**	**53,604**	**26,689**	**21,407**	**7,166**	**5,398**	**338,646**	**305,107**	**212,770**	**170,423**	**189,764**	**159,663**
Proved Developed Non-Producing												
Canada	624	554	136	106	132	94	8,330	6,209	–	–	2,280	1,788
United States	181	146	–	–	12	10	87	126	72,320	57,893	12,261	9,826
Total	**805**	**700**	**136**	**106**	**144**	**104**	**8,417**	**6,335**	**72,320**	**57,893**	**14,541**	**11,614**
Proved Undeveloped												
Canada	5,395	4,629	3,980	3,053	334	247	34,484	32,040	–	–	15,456	13,269
United States	17,484	14,025	–	–	1,088	925	8,731	10,749	126,342	101,084	41,084	33,589
Total	**22,879**	**18,654**	**3,980**	**3,053**	**1,422**	**1,172**	**43,215**	**42,789**	**126,342**	**101,084**	**56,540**	**46,858**
Total Proved												
Canada	29,163	25,582	30,806	24,566	6,203	4,541	336,199	300,638	–	–	122,204	104,796
United States	58,526	47,375	–	–	2,529	2,133	54,081	53,593	411,431	329,400	138,640	113,340
Total	**87,689**	**72,957**	**30,806**	**24,566**	**8,732**	**6,674**	**390,280**	**354,231**	**411,431**	**329,400**	**260,844**	**218,136**
Probable												
Canada	9,662	8,125	11,260	8,588	2,523	1,889	142,103	126,166	–	–	47,129	39,630
United States	52,678	42,263	–	–	3,106	2,570	32,342	32,601	189,430	151,530	92,746	75,522
Total	**62,340**	**50,388**	**11,260**	**8,588**	**5,629**	**4,459**	**174,445**	**158,767**	**189,430**	**151,530**	**139,875**	**115,152**
Total Proved Plus Probable												
Canada	38,825	33,708	42,066	33,154	8,726	6,430	478,302	426,804	–	–	169,334	144,426
United States	111,204	89,637	–	–	5,635	4,704	86,423	86,194	600,861	480,930	231,386	188,862
Total	**150,029**	**123,345**	**42,066**	**33,154**	**14,361**	**11,134**	**564,725**	**512,998**	**600,861**	**480,930**	**400,720**	**333,288**

Summary of Net Present Value of Future Net Revenue Attributable to Oil and Gas Reserves (Forecast Prices and Costs) As of December 31, 2013

	Net Present Value of Future Net Revenue Discounted at (%/Year)										
	Before Deducting Income Taxes					After Deducting Income Taxes					Unit
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**Value(1)**
	(in $ millions)										($/BOE)
Proved Developed Producing											
Canada	2,389	1,772	1,422	1,201	1,049	2,161	1,650	1,350	1,155	1,018	$15.85
United States	2,849	2,048	1,629	1,374	1,202	2,245	1,654	1,339	1,145	1,012	$23.30
Total	**5,238**	**3,820**	**3,051**	**2,575**	**2,251**	**4,406**	**3,304**	**2,689**	**2,300**	**2,030**	**$19.11**
Proved Developed Non-Producing											
Canada	74	54	43	36	31	55	42	34	29	25	$24.05
United States	225	163	131	111	97	135	97	78	67	59	$13.33
Total	**299**	**217**	**174**	**147**	**128**	**190**	**139**	**112**	**96**	**84**	**$14.98**
Proved Undeveloped											
Canada	434	198	96	43	11	326	142	62	20	(5)	$7.23
United States	871	414	216	109	43	523	235	108	38	(6)	$6.43
Total	**1,305**	**612**	**312**	**152**	**54**	**849**	**377**	**170**	**58**	**(11)**	**$6.66**
Total Proved											
Canada	2,897	2,025	1,561	1,280	1,091	2,542	1,834	1,446	1,204	1,038	$14.90
United States	3,945	2,624	1,976	1,594	1,342	2,903	1,986	1,525	1,249	1,065	$17.43
Total	**6,842**	**4,649**	**3,537**	**2,874**	**2,433**	**5,445**	**3,820**	**2,971**	**2,453**	**2,103**	**$16.21**
Probable											
Canada	1,482	740	469	333	254	1,096	544	343	244	186	$11.83
United States	3,451	1,642	968	641	456	2,071	969	555	359	250	$12.82
Total	**4,933**	**2,382**	**1,437**	**974**	**710**	**3,167**	**1,513**	**898**	**603**	**436**	**$12.48**
Total Proved Plus Probable											
Canada	4,379	2,765	2,030	1,613	1,345	3,638	2,378	1,789	1,448	1,224	$14.06
United States	7,396	4,266	2,944	2,235	1,798	4,974	2,955	2,080	1,608	1,315	$15.59
Total	**11,775**	**7,031**	**4,974**	**3,848**	**3,143**	**8,612**	**5,333**	**3,869**	**3,056**	**2,539**	**$14.92**

Note:

(1) Calculated using net present value of future net revenue before deducting income taxes, discounted at 10% per year, and net reserves. The unit values are based on net reserves volumes.

FORECAST PRICES AND COSTS

The forecast price and cost case assumes no legislative or regulatory amendments, and includes the effects of inflation. The estimated future net revenue to be derived from the production of the reserves includes the following price forecasts supplied by McDaniel as of January 1, 2014 (and utilized by NSAI and by the Corporation in its internal evaluations for consistency in the Corporation's reserves reporting) and the following inflation and exchange rate assumptions:

	Crude Oil				Natural Gas		Natural Gas Liquids				
							Edmonton Par Price				
Year	WTI(1)	Edmonton Light(2)	Alberta Heavy(3)	Sask Cromer Medium(4)	Alberta AECO Spot Price	U.S. Henry Hub Gas Price	Propanes	Butanes	Condensate & Natural Gasolines	Inflation Rate	Exchange Rate
	($US/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/MMbtu)	($US/MMbtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	(%/year)	($US/$Cdn)
2014	95.00	95.00	67.50	89.30	4.00	4.25	50.20	76.60	102.50	2.0	0.950
2015	95.00	96.50	70.40	90.70	4.25	4.50	50.50	77.80	101.60	2.0	0.950
2016	95.00	97.50	71.20	91.70	4.55	4.75	50.60	78.60	100.60	2.0	0.950
2017	95.00	98.00	71.50	92.10	4.75	5.00	51.30	79.00	101.20	2.0	0.950
2018	95.30	98.30	71.80	92.40	5.00	5.25	52.00	79.20	101.50	2.0	0.950
Thereafter	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	0.950

Notes:

(1) West Texas Intermediate at Cushing Oklahoma 40º API,0.5% sulphur.
(2) Edmonton Light Sweet 40º API,0.3% sulphur.
(3) Heavy Crude Oil 12º API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Midale Cromer Crude Oil 29º API,2.0% sulphur.
(5) Escalation varies until 2021 and is approximately 2% per year thereafter.

In 2013, the Corporation received a weighted average price (net of transportation costs but before hedging) of $69.07/bbl for heavy crude oil, $88.27/bbl for light and medium crude oil, $52.25/bbl for NGLs and $3.18/Mcf for natural gas and $3.42/Mcf for shale gas.

UNDISCOUNTED FUTURE NET REVENUE BY RESERVES CATEGORY

The undiscounted total future net revenue by reserves category as of December 31, 2013, using forecast prices and costs, is set forth below (columns or rows may not add due to rounding):

Reserves Category	Revenue	Royalties and Production Taxes	Operating Costs	Develop-ment Costs	Abandon-ment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
				(in $ millions)				
Proved Reserves								
Canada	7,887	1,192	3,164	394	240	2,897	355	2,542
United States	9,005	2,245	2,164	607	44	3,945	1,042	2,903
Total	16,892	3,437	5,327	1,001	284	6,842	1,397	5,445
Proved Plus Probable Reserves								
Canada	11,304	1,768	4,358	545	254	4,379	741	3,638
United States	16,474	4,206	3,366	1,451	55	7,396	2,422	4,974
Total	27,778	5,974	7,724	1,996	309	11,775	3,163	8,612

NET PRESENT VALUE OF FUTURE NET REVENUE BY RESERVES CATEGORY AND PRODUCTION GROUP

The net present value of future net revenue before income taxes by reserves category and production group as of December 31, 2013, using forecast prices and costs and discounted at 10% per year, is set forth below:

Reserves Category	Production Group	Net Present Value of Future Net Revenue Before Income Taxes (Discounted at 10%/year)	Unit Value[3]
		(in $ millions)	($/bbl, $/Mcf)
Canada			
Proved Reserves	Light and Medium Crude Oil[1]	629	$24.76
	Heavy Oil[1]	597	$24.30
	Natural Gas[2]	335	$1.23
	Shale Gas[4]	n/a	n/a
	Total	1,561	
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	775	$23.13
	Heavy Oil[1]	780	$23.55
	Natural Gas[2]	475	$1.22
	Shale Gas[4]	n/a	n/a
	Total	2,030	
United States			
Proved Reserves	Light and Medium Crude Oil[1]	1,304	$27.53
	Heavy Oil[1]	n/a	n/a
	Natural Gas[2]	34	$3.69
	Shale Gas[4]	638	$1.94
	Total	1,976	
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	2,104	$23.47
	Heavy Oil[1]	n/a	n/a
	Natural Gas[2]	49	$3.18
	Shale Gas[4]	790	$1.64
	Total	2,944	
Total			
Proved Reserves	Light and Medium Crude Oil[1]	1,934	$25.56
	Heavy Oil[1]	597	$24.30
	Natural Gas[2]	369	$1.31
	Shale Gas[4]	638	$1.94
	Total	3,537	
Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	2,879	$23.38
	Heavy Oil[1]	780	$23.55
	Natural Gas[2]	524	$1.30
	Shale Gas[4]	790	$1.64
	Total	4,974	

Notes:

(1) Including net present value of solution gas and other by-products.
(2) Including net present value of by-products, but excluding solution gas and by-products from oil wells.
(3) Calculated using net oil or net gas reserves and forecast price and cost assumptions. Presented in $/bbl for oil and $/Mcf for gas.
(4) No NGLs are associated with Shale Gas.

ESTIMATED PRODUCTION FOR GROSS RESERVES ESTIMATES

The volume of total production for the Corporation estimated for 2014 in preparing the estimates of gross proved reserves and gross probable reserves is set forth below. Actual 2014 production (including from the Fort Berthold property in the separate table below) may vary from the estimates provided by McDaniel and NSAI as the Corporation's actual development programs, timing and priorities may differ from the forecast of development by McDaniel and NSAI. Columns may not add due to rounding.

Gross Proved Reserves

Product Type	Canada				United States			
	Estimated 2014 Aggregate Production		Estimated 2014 Average Daily Production		Estimated 2014 Aggregate Production		Estimated 2014 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	4,361	Mbbls	11,947	bbls/day	6,917	Mbbls	18,951	bbls/day
Heavy Oil	1,653	Mbbls	4,530	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	6,014	Mbbls	16,477	bbls/day	6,917	Mbbls	18,951	bbls/day
Natural Gas Liquids	839	Mbbls	2,298	bbls/day	293	Mbbls	804	bbls/day
Total Liquids	6,853	Mbbls	18,774	bbls/day	7,210	Mbbls	19,755	bbls/day
Natural Gas	52,835	MMcf	144,752	Mcf/day	5,835	MMcf	15,987	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	61,738	MMcf	169,145	Mcf/day
Total	15,658	MBOE	42,900	BOE/day	18,473	MBOE	50,610	BOE/day

Gross Probable Reserves

Product Type	Canada				United States			
	Estimated 2014 Aggregate Production		Estimated 2014 Average Daily Production		Estimated 2014 Aggregate Production		Estimated 2014 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	195	Mbbls	534	bbls/day	1,316	Mbbls	3,606	bbls/day
Heavy Oil	108	Mbbls	296	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	303	Mbbls	830	bbls/day	1,316	Mbbls	3,606	bbls/day
Natural Gas Liquids	55	Mbbls	151	bbls/day	75	Mbbls	204	bbls/day
Total Liquids	358	Mbbls	981	bbls/day	1,391	Mbbls	3,810	bbls/day
Natural Gas	3,570	MMcf	9,782	Mcf/day	693	MMcf	1,899	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	2,244	MMcf	6,149	Mcf/day
Total	953	MBOE	2,611	BOE/day	1,880	MBOE	5,151	BOE/day

The following table sets forth McDaniel's estimated 2014 production for the Corporation's Fort Berthold property located in North Dakota, United States, as this field is estimated to account for more than 20% of the above estimate of the Corporation's 2014 production.

Estimated 2014 Production for Fort Berthold Property

Product Type	Gross Proved Reserves				Gross Probable Reserves			
	Estimated 2014 Aggregate Production		Estimated 2014 Average Daily Production		Estimated 2014 Aggregate Production		Estimated 2014 Average Daily Production	
Crude Oil								
Light and Medium Crude Oil	5,293	Mbbls	14,501	bbls/day	1,280	Mbbls	3,505	bbls/day
Heavy Oil	–	Mbbls	–	bbls/day	–	Mbbls	–	bbls/day
Total Crude Oil	5,293	Mbbls	14,501	bbls/day	1,280	Mbbls	3,505	bbls/day
Natural Gas Liquids	293	Mbbls	804	bbls/day	74	Mbbls	204	bbls/day
Total Liquids	5,586	Mbbls	15,304	bbls/day	1,354	Mbbls	3,709	bbls/day
Natural Gas	2,378	MMcf	6,515	Mcf/day	617	MMcf	1,692	Mcf/day
Shale Gas	–	MMcf	–	Mcf/day	–	MMcf	–	Mcf/day
Total	5,982	MBOE	16,390	BOE/day	1,457	MBOE	3,991	BOE/day

FUTURE DEVELOPMENT COSTS

The amount of development costs deducted in the estimation of net present value of future net revenue is set forth below. The Corporation intends to fund its development activities through internally generated cash flow and proceeds from the stock dividend program of the Corporation, as well as through debt or the issuance of Common Shares where required. The Corporation does not anticipate that the cost of obtaining the funds required for these development activities will have a material effect on the Corporation's disclosed oil and gas reserves or future net revenue attributable to those reserves. For additional information, see "*Business of the Corporation – Capital Expenditures and Costs Incurred*" and "*Business of the Corporation – Exploration and Development Activities*".

	Canada				United States			
	Proved Reserves		Proved Plus Probable Reserves		Proved Reserves		Proved Plus Probable Reserves	
Year	**Undiscounted**	**Discounted at 10%/year**	**Undiscounted**	**Discounted at 10%/year**	**Undiscounted**	**Discounted at 10%/year**	**Undiscounted**	**Discounted at 10%/year**
				(in $ millions)				
2014	149	145	160	155	330	315	398	379
2015	113	100	154	136	277	240	364	316
2016	31	25	95	78	–	–	344	271
2017	31	23	66	50	–	–	310	222
2018	19	13	19	13	–	–	21	14
Remainder	51	28	51	25	–	–	14	8
Total	394	334	545	458	607	555	1,451	1,209

RECONCILIATION OF RESERVES

Overview

The Corporation's total gross proved plus probable reserves at December 31, 2013 were approximately 400.7 MMBOE, up approximately 17.5% from year-end 2012. The Corporation's gross proved plus probable oil and NGLs reserves remained at 206.5 MMBOE and now represent approximately 52% of total proved plus probable gross reserves, down from 60% at year-end 2012. The Corporation replaced approximately 237% of its 2013 gross production through its exploration and development program, adding 76.2 MMBOE of proved plus probable reserves. Approximately 31% of the additions were oil and NGLs, representing the replacement of 157% the Corporation's 2013 oil and NGLs production. The largest amount of crude oil reserve additions were in the Corporation's Fort Berthold crude oil property in North Dakota. The largest amount of natural gas additions were in the Marcellus shale gas property, as a result of development activities and the acquisition of 143 Bcf of shale gas reserves. Approximately 90% of the acquired reserves in 2013 were attributable to the Marcellus. The Corporation sold 11.4 MMBOE of proved plus probable reserves in 2013, 8.6 MMBOE of which were associated with the disposition of the Corporation's non-core assets. As a result of the weak outlook for natural gas prices, approximately 31 Bcf of natural gas reserves were removed from the Corporation's reserves at year-end. Total proved plus probable natural gas reserves increased by approximately 43% from year-end 2012.

The following tables reconcile the Corporation's gross oil and natural gas reserves from December 31, 2012 to December 31, 2013, by country and in total, using forecast prices and costs. Certain columns may not add due to rounding.

CANADIAN OIL AND GAS RESERVES

Canada	Light & Medium Oil			Heavy Oil			Natural Gas Liquids		
Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2012	35,688	12,652	48,340	31,509	10,988	42,496	6,786	3,112	9,898
Acquisitions	1,580	290	1,870	–	–	–	19	3	23
Dispositions	(6,612)	(2,627)	(9,239)	–	–	–	(597)	(213)	(810)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	1,504	685	2,189	1,528	1,751	3,279	162	63	225
Economic Factors	491	(13)	478	55	57	113	(30)	(17)	(47)
Technical Revisions	(136)	(1,325)	(1,461)	820	(1,536)	(715)	844	(425)	419
Production	(3,352)	–	(3,352)	(3,107)	–	(3,107)	(982)	–	(982)
December 31, 2013	**29,163**	**9,662**	**38,825**	**30,806**	**11,260**	**42,066**	**6,203**	**2,523**	**8,726**

Canada	Associated and Non-Associated Gas (Natural Gas)			Shale Gas			Total		
Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2012	350,546	168,398	518,944	–	–	–	132,407	54,818	187,225
Acquisitions	1,676	283	1,959	–	–	–	1,879	340	2,219
Dispositions	(5,750)	(2,059)	(7,809)	–	–	–	(8,167)	(3,184)	(11,351)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	23,373	8,340	31,713	–	–	–	7,089	3,890	10,979
Economic Factors	(3,066)	(908)	(3,974)	–	–	–	5	(124)	(119)
Technical Revisions	31,502	(31,950)	(448)	–	–	–	6,779	(8,611)	(1,832)
Production	(62,083)	–	(62,083)	–	–	–	(17,788)	–	(17,788)
December 31, 2013	**336,199**	**142,103**	**478,302**	**–**	**–**	**–**	**122,204**	**47,129**	**169,334**

UNITED STATES OIL AND GAS RESERVES

United States	Light & Medium Oil			Heavy Oil			Natural Gas Liquids		
Factors	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2012	56,876	43,081	99,957	–	–	–	2,299	2,215	4,514
Acquisitions	30	681	711	–	–	–	2	40	42
Dispositions	–	–	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	5,184	14,475	19,659	–	–	–	227	907	1,134
Economic Factors	(556)	8	(548)	–	–	–	2	2	4
Technical Revisions	4,368	(5,567)	(1,199)	–	–	–	234	(58)	176
Production	(7,376)	–	(7,376)	–	–	–	(235)	–	(235)
December 31, 2013	**58,526**	**52,678**	**111,204**	**–**	**–**	**–**	**2,529**	**3,106**	**5,635**

(continued)

United States Factors	Associated and Non-Associated Gas (Natural Gas) Proved	Probable	Proved Plus Probable	Shale Gas Proved	Probable	Proved Plus Probable	Total Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2012	47,492	24,266	71,758	146,127	78,373	224,500	91,445	62,402	153,847
Acquisitions	11	266	277	117,668	25,686	143,354	19,645	5,046	24,691
Dispositions	–	–	–	–	–	–	–	–	–
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	3,206	7,333	10,539	168,634	89,619	258,253	34,051	31,541	65,591
Economic Factors	(1,125)	(19)	(1,144)	(17,140)	(8,877)	(26,017)	(3,598)	(1,473)	(5,071)
Technical Revisions	9,927	497	10,424	30,917	4,629	35,545	11,408	(4,770)	6,639
Production	(5,431)	–	(5,431)	(34,775)	–	(34,775)	(14,312)	–	(14,312)
December 31, 2013	**54,081**	**32,342**	**86,423**	**411,431**	**189,430**	**600,861**	**138,640**	**92,746**	**231,386**

TOTAL OIL AND GAS RESERVES

Total Factors	Light & Medium Oil Proved	Probable	Proved Plus Probable	Heavy Oil Proved	Probable	Proved Plus Probable	Natural Gas Liquids Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2012	92,564	55,733	148,297	31,509	10,988	42,496	9,085	5,327	14,412
Acquisitions	1,610	971	2,581	–	–	–	21	43	64
Dispositions	(6,612)	(2,628)	(9,239)	–	–	–	(597)	(213)	(810)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	6,688	15,161	21,848	1,528	1,751	3,279	389	970	1,359
Economic Factors	(65)	(5)	(70)	55	57	113	(28)	(15)	(43)
Technical Revisions	4,232	(6,892)	(2,660)	820	(1,536)	(715)	1,078	(483)	595
Production	(10,728)	–	(10,728)	(3,107)	–	(3,107)	(1,217)	–	(1,217)
December 31, 2013	**87,689**	**62,340**	**150,029**	**30,806**	**11,260**	**42,066**	**8,732**	**5,629**	**14,361**

Total Factors	Associated and Non-Associated Gas (Natural Gas) Proved	Probable	Proved Plus Probable	Shale Gas Proved	Probable	Proved Plus Probable	Total Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MMcf)	(MBOE)	(MBOE)	(MBOE)
December 31, 2012	398,038	192,664	590,702	146,127	78,373	224,500	223,852	117,220	341,072
Acquisitions	1,688	548	2,236	117,668	25,686	143,354	21,524	5,386	26,910
Dispositions	(5,750)	(2,059)	(7,809)	–	–	–	(8,167)	(3,184)	(11,351)
Discoveries	–	–	–	–	–	–	–	–	–
Extensions and Improved Recovery	26,579	15,673	42,251	168,634	89,619	258,253	41,140	35,431	76,570
Economic Factors	(4,191)	(927)	(5,118)	(17,140)	(8,877)	(26,017)	(3,593)	(1,597)	(5,189)
Technical Revisions	41,429	(31,453)	9,976	30,917	4,629	35,545	18,188	(13,380)	4,807
Production	(67,513)	–	(67,513)	(34,775)	–	(34,775)	(32,100)	–	(32,100)
December 31, 2013	**390,279**	**174,446**	**564,725**	**411,431**	**189,430**	**600,861**	**260,844**	**139,875**	**400,720**

UNDEVELOPED RESERVES

The following tables disclose the volumes of proved undeveloped reserves and probable undeveloped reserves of the Corporation that were first attributed in the years indicated.

Proved Undeveloped Reserves

	Crude Oil					
Year(1)	Heavy	Light and Medium	NGLs	Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
Aggregate prior to 2011	6,849	25,017	1,889	272,098	15,747	81,729
2011	885	10,397	572	8,629	25,817	17,595
2012	2,835	6,956	372	2,628	21,876	14,247
2013	1,526	2,335	36	14,905	67,821	17,685

Probable Undeveloped Reserves

	Crude Oil					
Year(1)	Heavy	Light & Medium	NGLs	Natural Gas	Shale Gas	Total
	(Mbbls)	(Mbbls)	(Mbbls)	(MMcf)	(MMcf)	(MBOE)
Aggregate prior to 2011	2,616	12,152	975	153,736	60,196	51,398
2011	127	15,178	871	11,515	21,135	21,618
2012	504	15,332	1,054	26,082	55,224	30,441
2013	1,751	12,844	827	11,990	98,491	33,836

Note:

(1) First attributed volumes include additions during the year and do not include revisions to previous undeveloped reserves.

The Corporation attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information and the optimization of existing fields. The Corporation has been very active for the last several years in drilling and developing these undeveloped reserves and, based on the estimates of future capital expenditures, the Corporation expects this to continue.

SIGNIFICANT FACTORS OR UNCERTAINTIES

A decrease in future commodity prices, and in particular natural gas prices, relative to the forecasts described above under "– *Forecast Prices and Costs*" could have a negative impact on the Corporation's reserves, and in particular on the development of Undeveloped Reserves, unless future development costs are also reduced. Other than the foregoing and the factors disclosed or described in the tables above, the Corporation does not anticipate any other significant economic factors or other significant uncertainties which may affect any particular components of its reserves data.

For further information, see "*Risk Factors – The Corporation's actual reserves and resources will vary from its reserve and resource estimates, and those variations could be material*".

PROVED AND PROBABLE RESERVES NOT ON PRODUCTION

The Corporation has approximately 16.9 MMBOE of proved plus probable reserves which are capable of production but which, as of December 31, 2013, were not on production. These reserves have generally been non-producing for periods ranging from a few months to more than five years. In general, these reserves are related to commercially producible volumes that are not producing due to production requirements of other reserve formations or zones in the same well bore, or are related to reserves volumes which require the completion of infrastructure before production can begin.

Supplemental Operational Information

SAFETY AND SOCIAL RESPONSIBILITY

The Corporation strives to develop and operate its oil and natural gas assets in a socially responsible manner and places a high priority on preserving the quality of the environment, protecting the health and safety of its employees, contractors and the public in the communities in which it operates and promoting active and open collaboration with its stakeholders. Additionally, the Corporation actively participates in industry recognized programs that support its sustainable mindset, which expects continuous improvement.

The Corporation has a Health and Safety Policy, an Environment Policy and a Stakeholder Engagement Policy that articulate its commitment to safety and social responsibility ("**S&SR**"). These policies apply to any activities undertaken by or on behalf of the Corporation.

The Health and Safety Policy articulates the Corporation's commitment to protecting the health and safety of all persons and communities involved in, or affected by, its business activities. The Health and Safety Policy outlines specific commitments, including: (i) striving to ensure no harm to employees, contractors or the public; (ii) complying with relevant acts, codes, laws, regulations, standards and procedures; (iii) providing resources, training and technology to meet health and safety objectives; (iv) consulting with stakeholders on issues related to health and safety; and (v) auditing and inspecting operations as part of continuously improving safe work practices.

The Environment Policy articulates the Corporation's commitment to conducting its activities within the environmental regulations that govern the oil and gas industry within each of its operating jurisdictions and to also proactively mitigate impacts on the environment. The Environment Policy states the Corporation will: (i) consider actions taken in the context of their economic, environmental and social effects; (ii) safeguard the environment with actions, including spill prevention and the mitigation of gas flaring and venting, and be prepared to provide a timely and effective response to unexpected releases of environmental contaminants; (iii) work to reduce waste and improve the efficiency of fresh water use; and (iv) work to improve energy efficiency.

The Stakeholder Engagement Policy articulates the Corporation's commitment to engaging with its stakeholders in a way that fosters mutually beneficial relationships to promote positive economic and social development in its operating areas. The Stakeholder Engagement Policy states the Corporation will: (i) actively and openly collaborate with its stakeholders; (ii) ensure its stakeholders have access to timely, accurate information regarding current or planned operations and projects; (iii) strive to provide local suppliers of goods and services that meet the Corporation's procurement standards with opportunities to participate in its operations and projects; and (iv) develop long-lasting relationships based on trust, mutual respect and common understanding where the Corporation's activities will have a long-lasting impact on the communities in which it operates.

The Safety and Social Responsibility Committee of the Corporation's board of directors is responsible for review of the policies, performance and continuous improvement of the Corporation's Safety and Social Responsibility Management System (the "**S&SR System**"), ensuring that Corporation's activities are planned and executed in a safe and responsible manner and for review to ensure there are adequate systems in place to support ongoing compliance. Additionally, the committee is responsible for oversight of all results and action plans that have been initiated or proposed by the Corporation with respect to S&SR.

In 2013, a third party comprehensive assessment of the S&SR System was conducted to evaluate the suitability of the S&SR System for the Corporation's operations. This assessment also evaluated the S&SR System against generally accepted best practices within the industry and the international standard for Occupational Health & Safety (ISO18001) and for Environmental Management Systems (ISO14001). In conjunction with the S&SR System, the Corporation utilizes a Sustainability Information Management System to maintain its corporate health and safety and social responsibility performance data.

Health and Safety

The Corporation's employee recordable injury frequency rate increased from 0.40 injuries per 200,000 man hours in 2012 to 0.54 injuries per 200,000 man hours in 2013. The Corporation's contractor total recordable injury frequency decreased from 1.26 injuries per 200,000 man hours in 2012 to 1.23 injuries per 200,000 man hours in 2013. The Corporation's 2013 combined employee/contractor recordable injury frequency rate was 0.96 injuries per 200,000 man hours, unchanged from 2012.

Health and safety risks influence workplace practices, operating costs and the establishment of regulatory standards. The Corporation maintains a comprehensive health and safety management system designed to:

- increase emphasis on safety awareness and to promote continuous improvement and safety excellence;
- provide staff with the training and resources needed to complete work safely;
- support and participate in the CAPP Responsible Canadian Energy Program to develop and improve safety performance;
- incorporate hazard assessment and risk management as an integral part of everyday business; and
- monitor performance to ensure that its operations comply with all legal obligations and its internally-imposed standards.

The health and safety component of the S&SR System is reviewed annually for continuous improvement opportunity. Every three years, the Health and Safety Management System is subject to a third-party audit utilizing the Enform Certificate of Recognition ("**COR**") Audit Protocol. Third party maintenance audits against the COR Audit Protocol are conducted each year between the Health and Safety Management System audit. In 2012, the Corporation successfully renewed its COR certification.

The Corporation continues to develop and implement prevention measures and safety management program improvements to support its focus and commitment for an injury-free workplace.

Environment

The Corporation is committed to meeting its responsibilities to protect the environment through a variety of programs and actively monitors its compliance with all regulations. In particular, the Corporation engages in the following activities:

- The Corporation supports and participates in the CAPP Responsible Canadian Energy program. The Corporation's participation in this program since its inception demonstrates its commitment to responsible resource development and to continuous improvement in environment, health and safety and social performance;
- Site abandonment, remediation and reclamation capital expenditures for the Corporation's Canadian properties in 2013 totalled $14.324 million ($10.013 million on operated properties and $4.311 million on non-operated properties). The Corporation's U.S. abandonment capital expenditures totalled $2.282 million (operated and non-operated). The Corporation received 16 reclamation certificates in 2013 by returning sites to that of equivalent land capability;
- The Corporation conducts annual property reviews in Canada with specific corrosion risk management goals designed to ensure compliance with health, safety and environmental legislation and regulations and in 2013, 83 areas were reviewed;
- The Corporation continues to manage risk through the implementation of a Pipeline Risk Program and various other pipeline integrity activities including inspection of pipelines at water crossings. The Corporation reviews each pipeline system annually. The Corporation is currently enhancing this program to include a wider range of hazards to identify and mitigate risks to decrease future significant pipeline failure incidents;
- The Corporation continued its internal facility inspections program and completed 49 inspections at major Canadian facilities in 2013. The average score of environment and regulatory compliance resulting from the internal inspection program in 2013 was 90%. The Corporation also completed five environment and regulatory compliance audits in 2013 at its Canadian facilities and averaged a score of 80% to 90% compliance. In addition, there were 58 well site inspections completed in Canada;
- The Corporation also continued its internal environmental and regulatory inspections in the United States in 2013. Frequent inspections were conducted at the Corporation's West Virginia, Pennsylvania, Montana and North Dakota sites along with routine drilling rig inspections conducted by field safety personnel; and
- The Corporation has estimated its direct emissions in 2013 to be approximately 613,397 carbon dioxide equivalent tonnes per year, which is slightly more than the Corporation's direct emissions in 2012 of 612,763 carbon dioxide equivalent tonnes per year. The estimated numbers will be adjusted as additional data becomes available. In 2013, the Corporation completed 59 fugitive emissions infrared surveys at its Canadian facilities to detect losses from leaks and vents and is working to repair identified leaks.

Greenhouse gas regulations have been enacted in British Columbia, Alberta and at the federal level in Canada and the U.S. In British Columbia, the Corporation is subject to the carbon tax introduced in mid-2008. The total carbon tax paid was approximately $967,502 in 2013. In addition, the Corporation is required to report third party verified greenhouse gas emissions annually to the government of British Columbia under the *Cap and Trade Act* (British Columbia) (the "**BCCTA**"). The Corporation is not subject to the Canadian greenhouse gas emissions reporting requirement as it does not currently operate facilities above the 50,000 tonnes of carbon dioxide equivalent per year threshold.

However, the Corporation is subject to the reporting requirement in the U.S. under the *Clean Air Act* and the Mandatory Reporting of Greenhouse Gases Rule. The latest of these reports was submitted to the U.S. Environmental Protection Agency on March 31, 2013 for the 2012 operational year. The report for the 2013 operational year will be submitted on March 31, 2014. For more information on the environmental regulation applicable to the Corporation, see "*Industry Conditions – Environmental Regulation*."

The Corporation endeavours to carry out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice. In particular, with respect to hydraulic fracturing, the Corporation complies with all current Canadian and U.S. regulations and adheres to all CAPP Hydraulic Fracturing Operating Practices. The Corporation proactively employs alternative fracturing technology such as foams, gelled water and reclaimed water to reduce the amount of fresh water required during the fracturing process. The Corporation actively seeks opportunities to collaborate with other area operators to share flowback fluid where feasible through inter-company transfers. Although the Corporation proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the United States impose more stringent compliance requirements surrounding hydraulic fracturing.

The Corporation carries insurance to cover a portion of its property losses, liability and business interruption. Health, safety, environmental and regulatory updates and risks are reviewed regularly by the Safety & Social Responsibility Committee of the Corporation's board of directors. At present, the Corporation believes that it is, and expects to continue to be, in compliance with all material applicable environmental laws and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet its ongoing environmental obligations.

Overall, the Corporation strives to operate in a socially responsible manner and believes its health, safety and environmental initiatives confirm its ongoing commitment to environmental stewardship and the health and safety of its employees, contractors and the general public in the communities in which it operates. Annually, the Corporation identifies key focus areas to support this commitment and sets forth strategic reduction targets. The Corporation believes that by monitoring metrics, identifying areas for improvement and implementing strategies, processes and procedures in those key focus areas, the Corporation can reduce its environmental impact.

INSURANCE

The Corporation carries insurance coverage to protect its assets at or above the standards typical within the oil and natural gas industry. Insurance levels are determined and acquired by the Corporation after considering the perceived risk of loss and appropriate coverage, together with the overall cost. The Corporation currently purchases insurance to protect against third party liability, property damage, business interruption, pollution and well control. In addition, liability coverage is also carried for the directors and officers of the Corporation.

PERSONNEL

As at December 31, 2013, the Corporation employed a total of 707 persons, including full-time benefit and payroll consultants, 575 of whom were in Canada and 132 of whom were in the United States.

Description of Capital Structure

The authorized capital of the Corporation consists of an unlimited number of Common Shares and a number of preferred shares, issuable in series ("**Preferred Shares**"), which are limited to an amount equal to not more than one-quarter of the number of issued and outstanding Common Shares at the time of the issuance of any such Preferred Shares. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and the Preferred Shares. Copies of the Corporation's articles of amalgamation and bylaws were filed on the Corporation's SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov on January 2, 2013 and January 5, 2011, respectively.

COMMON SHARES

Holders of Common Shares are entitled to receive notice of and to attend all meetings of shareholders of the Corporation and to one vote at such meetings for each Common Share held. The holders of the Common Shares are, at the discretion of the Corporation's board of directors and subject to applicable legal restrictions and subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Corporation, entitled to receive any dividends declared by the Corporation on the Common Shares and to share in the remaining property of the Corporation upon liquidation, dissolution or winding-up.

The articles of the Corporation, as amended and restated on May 11, 2012, contain provisions facilitating payment of dividends on Common Shares through issuance of Common Shares in circumstances where a shareholder of the Corporation validly elects to receive payment of dividends, in whole or in part, in the form of Common Shares (the portion of the dividend payable in Common Shares being referred to in this paragraph as "**stock dividends**"). In particular, the terms of Common Shares implement procedures for: (i) a shareholder of the Corporation to elect to accept stock dividends; (ii) determining the value and number of Common Shares to be distributed by way of a stock dividend; (iii) accounting for the entitlement of shareholders of the Corporation to fractional Common Shares resulting from stock dividends; (iv) authorizing the sale of Common Shares issued in respect of stock dividends to satisfy tax withholding obligations or to comply with foreign laws or regulations applicable to a shareholder of the Corporation, if required; and (v) payment of cash in respect of fractional Common Shares upon a person ceasing to be a registered shareholder of the Corporation. See "*Dividends and Distributions – Stock Dividend Program*".

PREFERRED SHARES

There are no Preferred Shares outstanding as of the date of this Annual Information Form. The Preferred Shares may be issued from time to time in one or more series with such rights, restrictions, privileges, conditions and designations attached thereto as shall be fixed from time to time by the Corporation's board of directors. Subject to the provisions of the ABCA, the Preferred Shares of each series shall rank in parity with the Preferred Shares of every other series. The Preferred Shares shall be entitled to preference over the Common Shares and any other shares of the Corporation ranking junior to the said Preferred Shares with respect to payment of dividends and the distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, to the extent fixed in the case of each respective series, and may also be given such other preferences over the Common Shares and any other shares of the Corporation ranking junior to the said Preferred Shares as may be fixed in the case of each such series.

SHAREHOLDER RIGHTS PLAN

The continuation and amendment and restatement of the Shareholder Rights Plan was approved by shareholders of the Corporation, including by requisite number of the Corporation's "Independent Shareholders" (as defined in the Shareholder Rights Plan), at the annual meeting held on May 10, 2013. The continuation of the Shareholder Rights Plan must next be approved by the Corporation's "Independent Shareholders" at the annual meeting of shareholders of the Corporation to be held 2016, failing which it will expire at the end of such meeting. The Shareholder Rights Plan, under which Computershare Trust Company of Canada acts as rights agent, generally provides that, following the acquisition by any person or entity of 20% or more of the issued and outstanding Common Shares (except pursuant to certain permitted or excepted transactions) and upon the occurrence of certain other events, each holder of Common Shares, other than such acquiring person or entity, shall be entitled to acquire Common Shares at a discounted price. The Shareholder Rights Plan is similar to other shareholder rights plans adopted in the energy sector. A copy of the Shareholder Rights Plan was filed on May 10, 2013 as a "Security holders documents" on the Corporation's

SEDAR profile at www.sedar.com and on the Corporation's EDGAR profile at www.sec.gov, and is available on the Corporation's website at www.enerplus.com under "Corporate Governance".

SENIOR UNSECURED NOTES

Enerplus has issued Senior Unsecured Notes, of which US$696.6 million and CDN$70.0 million principal amounts were outstanding at December 31, 2013. Certain terms of the Senior Unsecured Notes are summarized below:

Issue Date	Original Principal	Remaining Principal	Coupon Rate	Interest Payment Dates	Maturity Date	Term
May 15, 2012	CDN$30 million	CDN$30 million	4.34%	May 15 and November 15	May 15, 2019	Bullet payment on maturity
May 15, 2012	US$20 million	US$20 million	4.40%	May 15 and November 15	May 15, 2022	Bullet payment on maturity
May 15, 2012	US$355 million	US$355 million	4.40%	May 15 and November 15	May 15, 2024	Principal payment required in five equal annual installments beginning May 15, 2020
June 18, 2009	CDN$40 million	CDN$40 million	6.37%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$40 million	US$40 million	6.82%	June 18 and December 18	June 18, 2015	Bullet payment on maturity
June 18, 2009	US$225 million	US$225 million	7.97%	June 18 and December 18	June 18, 2021	Principal payments required in five equal annual installments beginning June 18, 2017
October 1, 2003	US$54 million	US$21.6 million	5.46%	April 1 and October 1	October 1, 2015	Two remaining principal payments of equal annual installments required on October 1, 2014 and 2015
June 19, 2002	US$175 million	US$35 million	6.62%	June 19 and December 19	June 19, 2014	Final principal payment of equal annual installment required on June 19, 2014

For additional information see "*Material Contracts and Documents Affecting Securityholder Rights*".

BANK CREDIT FACILITY

As of December 31, 2013, the Corporation had $214.0 million drawn on a $1.0 billion unsecured, covenant-based credit facility with a syndicate of financial institutions maturing October 31, 2016. For a description of the Bank Credit Facility, see Note 8 to the Corporation's audited consolidated financial statements for the year ended December 31, 2013. See also "*Material Contracts and Documents Affecting Securityholder Rights*".

Dividends and Distributions

DIVIDEND POLICY AND HISTORY

The Corporation's board of directors is responsible for determining the dividend policy of the Corporation. The dividend policy must comply with the requirements of the ABCA, including satisfying the solvency test applicable to ABCA corporations. The Corporation has currently established a dividend policy of paying monthly dividends to holders of Common Shares. The dividend record date is on or about the 5^{th} day of each calendar month (or the immediately preceding business day), and the corresponding dividend payment date is on or about the 20th day of such month. However, any decision to pay dividends on the Common Shares will be made by the Corporation's board of directors on the basis of the relevant conditions existing at such future time, and there can be no guarantee that the Corporation will maintain its current dividend policy. Dividend amounts will likely vary, and there can be no assurance as to the level of dividends that will be paid or that any dividends will be paid at all. See "*Risk Factors – Dividends on the Corporation's Common Shares are variable*". Monthly cash dividends paid to U.S. resident shareholders are converted to U.S. dollars based upon the actual Canadian to U.S. dollar exchange rate on the dividend payment date, and accordingly, shareholders that are not resident in Canada are subject to foreign exchange rate risk on such payments.

The table below sets forth the dividends paid or declared by the Corporation in 2011, 2012, 2013 and January and February of 2014:

Month	2014	2013	2012	2011
January	$ 0.09	$ 0.09	$ 0.18	$ 0.18
February	0.09	0.09	0.18	0.18
March	N/A	0.09	0.18	0.18
April	N/A	0.09	0.18	0.18
May	N/A	0.09	0.18	0.18
June	N/A	0.09	0.18	0.18
July	N/A	0.09	0.09	0.18
August	N/A	0.09	0.09	0.18
September	N/A	0.09	0.09	0.18
October	N/A	0.09	0.09	0.18
November	N/A	0.09	0.09	0.18
December	N/A	0.09	0.09	0.18

For certain tax information relating to the dividends paid on the Common Shares for Canadian and U.S. federal income tax purposes, please refer to the Corporation's website at www.enerplus.com.

Shareholders are advised to consult their tax advisors regarding questions relating to the tax treatment of dividends paid by the Corporation. For additional information on potential risks associated with the taxation of dividends paid by the Corporation, see "*Risk Factors*".

STOCK DIVIDEND PROGRAM

Effective May 11, 2012, the Corporation implemented a stock dividend program pursuant to which shareholders of the Corporation may elect to receive dividends in the form of Common Shares, instead of receiving a cash dividend, issued at a deemed price of 95% of the five day weighted average trading price of the Common Shares on the TSX immediately prior to the applicable dividend payment date. The stock dividend program is available to all shareholders of the Corporation and it replaced the dividend reinvestment plan of the Corporation, which was terminated on May 25, 2012. For additional information on the Corporation's stock dividend program and to obtain copies of the documents related to the program, see the Corporation's website at www.enerplus.com under "*Investor Information – Dividends and Tax Info – Stock Dividend Program*".

Industry Conditions

OVERVIEW

The oil and natural gas industry is subject to extensive controls and regulation governing its operations (including land tenure, exploration, development, production, refining, transportation, marketing, remediation, abandonment and reclamation) imposed by legislation enacted by various levels of government. The oil and natural gas industry is also subject to agreements among the various federal, provincial and state governments with respect to pricing and taxation of oil and natural gas. Although it is not expected that any of these controls, regulations or agreements will affect the Corporation's operations in a manner materially different than they would affect other oil and gas issuers of similar size, the controls, regulations and agreements should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

The Corporation owns oil and natural gas properties and related assets in Canada (primarily in Alberta, Saskatchewan and British Columbia) and in Montana, North Dakota, Pennsylvania, West Virginia and Wyoming in the United States. The Corporation's U.S. oil and natural gas operations are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. The Corporation's U.S. operations are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

ROYALTIES AND INCENTIVES

In addition to federal regulations, each province in Canada and each U.S. state has legislation and regulations which govern oil and gas holdings and land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases, and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. In all U.S. jurisdictions, producers of oil and natural gas are typically required to pay annual rental payments in respect of federal, state and freehold leases until production begins. Upon commencement of production, royalties and production taxes are paid in respect of oil and natural gas produced from federal, state and freehold lands. Producers of U.S. Indian leases are required to pay annual rental payments regardless of well production. Royalty and production tax regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown-owned lands in Canada and federal and state lands in the U.S. are determined by negotiations between the freehold mineral owner and the lessee. Crown royalties in Canada and federal, U.S. Indian and state royalties and production taxes in the U.S. are determined by government regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties or net profits or net carried interests.

From time to time, the federal and provincial governments in Canada and the federal and state governments in the U.S. have established incentive programs which have included royalty rate or production tax reductions (including for specific wells), royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. If applicable, oil and natural gas royalty holidays, reductions and tax credits would effectively reduce the amount of royalties paid by oil and gas producers to the applicable governmental entities.

LAND TENURE

Crude oil and natural gas located in the western Canadian provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying periods and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned, and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Crude oil and natural gas located in the U.S. is predominantly owned by private owners. The Federal Government (Bureau of Land Management) (the "**BLM**") and the state in which the minerals are located also may hold ownership to such rights. These owners, from governmental bodies to private individuals, grant rights to explore for and produce oil and gas pursuant to leases, licenses and permits for varying periods and on conditions including requirements to perform specific work or make payments. As to those rights held by private owners, all terms and conditions may be negotiated. For those rights held by governmental agencies, typically the terms and conditions of the oil and gas lease have been predetermined by each governing or regulatory body. Substantially all of the leaseholds currently owned by the Corporation in the U.S. have been granted through private individuals.

The majority of the Corporation's operations in North Dakota take place on the Fort Berthold Indian Reservation (the "**FBIR**") and involve allotee lands, which are lands that are administered by the Bureau of Indian Affairs (the "**BIA**") but owned by individual band members. As such, these operations are governed by both state and federal regulations. The federal regulations are enforced by U.S. federal departments such as the BIA, the BLM, and the U.S. federal Environmental Protection Agency (the "**U.S. EPA**"). Federal U.S. regulations may differ significantly from regulations generally applicable to non-federally regulated lands and, as a consequence, have the effect of slowing or halting the Corporation's developments on the FBIR.

A lease may generally be continued after the initial term provided certain minimum levels of exploration or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions. To develop minerals, including oil and natural gas, it is necessary for the mineral estate owner to have access to the surface estate. Under common law, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling, including notification requirements and to provide compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

ENVIRONMENTAL REGULATION

The oil and natural gas industry is subject to environmental regulation pursuant to federal, provincial/state and local legislation and regulation. These requirements provide for environmental protection and apply restrictions and prohibitions regarding disturbances and releases or emissions of various substances produced or utilized in association with oil and gas industry operations. In addition, legislation and regulation requires that well, pipeline and facility sites are abandoned and reclaimed to the satisfaction of the applicable authorities. Environmental laws may impose remediation obligations with respect to a property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with these requirements can involve significant expenditures. A breach of such requirements may result in the imposition of material fines and penalties, the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage or the issuance of clean-up orders.

In British Columbia, energy projects may be subject to review pursuant to the provisions of the *Environmental Assessment Act* (British Columbia), which rolls the previous processes for the review of major energy projects into a single environmental assessment process that contemplates public participation in the environmental review. Other environmental protection and management measures, including reclamation, are governed by the *Oil and Gas Activities Act* (British Columbia) and the *Environmental Management Act* (British Columbia). In Alberta, environmental compliance is governed by the *Environmental Protection and Enhancement Act* (Alberta) and the *Oil and Gas Conservation Act* (Alberta), both of which impose environmental responsibilities on oil and natural gas operators and working interest holders in Alberta and impose penalties for violations, which may be significant. In Saskatchewan, environmental compliance is governed by the *Environmental Management and Protection Act* (Saskatchewan), the *Environmental Assessment Amendment Act* (Saskatchewan) and the *Oil and Gas Conservation Act* (Saskatchewan).

In 2008, the Province of British Columbia instituted a carbon tax that applies to all fuel users and producers in the province, as well as the BCCTA, which requires third party verified greenhouse gas emissions to be reported annually. See "*Supplemental Operational Information – Health, Safety and Environment – Environment*". The Province of British Columbia is in discussions with stakeholders and partners of the Western Climate Initiative to develop an Emissions Trading Regulation and an Offsets Regulation under the BCCTA in order to price carbon and to reduce greenhouse gas emissions of regulated emitters through a regional cap and trade program. The Corporation is unable to estimate the future potential compliance costs of these pending regulations without a carbon price or an allocation of emission allowances. However, given the Corporation's current hydrocarbon production levels in British Columbia and a current price of carbon offsets in the marketplace of approximately $15 per tonne of carbon dioxide equivalent, the Corporation does not expect such costs to be material.

The Province of Alberta has instituted emission reduction targets for large emitters (e.g., 100,000 tonnes of carbon dioxide per year at a single facility), which could result in increased capital expenditures and operating costs. Currently, the Corporation does not operate any facility classed within this large emitter category. In 2010, the Alberta provincial government and the Canadian federal government aligned in support of regulations that require the reporting of greenhouse gas emissions at facilities that meet or exceed a 50,000 tonne per year carbon dioxide equivalent emissions threshold. Currently, the Corporation does not operate any facility classed within this category. Additionally, the Province of Saskatchewan has passed, but not yet proclaimed, the *Management and Reduction of Greenhouse Gases Act* (Saskatchewan), which would require regulated emitters to report and reduce their greenhouse gas emissions below a prescribed amount below their individual baseline emission level. The Corporation does not operate any facility classed within the regulated emitter category in Saskatchewan based on the 50,000 tonne per year carbon dioxide equivalent emissions threshold.

The Province of Alberta has instituted the *Responsible Energy Development Act* wherein a new, single regulatory body for upstream oil and gas was established. This single regulator, the Alberta Energy Regulator ("**AER**"), is a merger of the Energy Resources Conservation Board and the Alberta Environment and Sustainable Resource Development. The AER now has responsibility over the *Public Lands Act* and the *Mines and Minerals Act* and will eventually have responsibility over the *Water Act* and the *Environmental Protection and Enhancement Act* for oil and gas operations. The intention of this merger is to provide a comprehensive streamlined regulatory process.

In the United States, oil and gas operations are regulated at the federal, state, county and tribal levels of government. At the federal level, well planning and permitting is primarily regulated by the U.S. Department of Interior (BLM and BIA) for operations on public and tribal lands under the *Federal Land Policy and Management Act* and the *National Environmental Policy Act*. Environmental conservation and cultural and natural resources protection at the federal level are administered by numerous agencies under multiple statutes.

Environmental planning, permitting and compliance related to media protection and contaminants at the federal level are administered by the U.S. EPA or by various states whose programs have been granted primacy by the U.S. EPA. The U.S. EPA governs federal legislation, including the *Clean Air Act*, the *Clean Water Act*, the *Resource Conservation and Recovery Act* (other than oil and gas exempt wastes), the *Comprehensive Environmental Response, Compensation and Liability Act*, the *Oil Pollution Act*, the *Emergency Planning and Community Right-to-Know Act* and the *Safe Drinking Water Act* and *Federal Executive Orders*.

The Corporation's U.S. operations are subject to various regulations, including those relating to well permits, linear facilities, hydraulic fracturing, underground injection and setbacks (buffers) for environmental protection, including a number of state agencies regulating oil and as activities. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, state water quality, fish, wildlife, visual quality, transportation, noise, spills and incidents, and transportation.

The U.S. EPA announced on December 7, 2009 its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment. These findings by the U.S. EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal *Clean Air Act*. One such regulation that has been issued is the Mandatory Reporting of Greenhouse Gases Rule in which, petroleum and natural gas systems above a certain threshold at an onshore basin level are required to submit an annual greenhouse gas emissions report. The Corporation is subject to this regulation and reporting requirement.

Additional regulations affecting the Corporation's U.S. operations include the following: the approval and promulgation of the Federal Implementation Plan for Oil and Natural Gas Well Production Facilities, Fort Berthold Indian Reservation (Mandan, Hidats and Arikara nations), North Dakota and the Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. These regulations provide emission control requirements for the Corporation's U.S. assets, as well as increased monitoring, recordkeeping, reporting, and regulatory oversight.

At the request of Congress, in 2011, the U.S. EPA began research under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. The purpose of the study is to assess the potential impacts of hydraulic fracturing on drinking water resources, and to identify the driving factors that may affect the severity and frequency of such impacts. The focus is primarily on hydraulic fracturing of shale formations to extract natural gas, with some study of other oil-and gas-producing formations, including tight sands, and coalbeds. The BLM, which regulates oil and gas operations located on federal and tribal lands, published its latest proposed hydraulic fracturing rules on May 16, 2013. All of the Corporation's operations on the Fort Berthold Indian Reservation are regulated by the BLM. Based on the Corporation's discussion with the BLM, the BLM is currently in the process of sorting through approximately 1.7 million comments received in response to the proposed rule. The BLM has provided no update regarding a schedule for finalizing the rule.

Congress has also initiated various countermeasures aimed at restricting federal agencies' authority to impose new hydraulic fracturing regulations. The political response from Congress is largely in reaction to the BLM's proposed rules, the lingering EPA study and several other federal agency efforts to study the issue. The intent of these countermeasures is to limit federal over-reach on an issue that is considered best managed at the state level.

All U.S. states the Corporation operates in have updated their regulation on hydraulic fracturing disclosure. The requirements fall within two basic categories: (i) design and operational requirements; and (ii) information disclosure. Additionally, Pennsylvania and West Virginia have rules applicable to the tracking of water usage and management of flowback water. North Dakota, Montana, Pennsylvania and West Virginia all require operators to disclose information about the chemicals used in their completions; Montana, Pennsylvania and West Virginia prescribe what chemicals that can be used by operations in their completions. North Dakota requires the posting of this information on the internet-based chemical registry FracFocus. Montana allows operators to use FracFocus in lieu of reporting. The required chemical reporting is not substantially different between the state and FracFocus requirements.

FracFocus is operated by the Ground Water Protection Council, a group of state water officials, and the Interstate Oil and Gas Compact Commission, an association of oil and gas producing states. The online registry was created in 2011, in response, at least in part, to concerns from landowners about the chemical content of fracturing fluids that were being injected into oil and gas wells on their land as well as adjacent properties. FracFocus is widely accepted among the petroleum industry, and the Corporation has determined to utilize the registry in all four states in which it operates. Currently, FracFocus lists over 700 companies as registry participants.

Implementation of more stringent environmental regulations on the Corporation's U.S. operations could affect the capital and operating expenditures and plans for the Corporation's U.S. operations. The Corporation minimizes the potential of these impacts to U.S. operations in many ways, including through the participation and membership in trade organizations, such as North Dakota Petroleum Council, Montana Petroleum Association, West Virginia Oil and Natural Gas Association, Independent Petroleum Association of America and Western Energy Alliance. In addition, the Corporation participates directly in legislative hearings, rulemaking processes, meetings with state officials and local stakeholder groups, and provides both written and verbal comment on proposed legislation and regulation. As in Canada, the Corporation's U.S. operations endeavour to carry out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice.

Subsequent to the International Climate Change meeting in Copenhagen in December 2009 the governments of the United States and Canada committed to a 17% reduction in greenhouse gas emissions by 2020 relative to a 2005 baseline. The Government of Canada is working towards this target on a sector by sector basis but has yet to finalize regulations pertaining to the oil and gas sector. A recent report from the National Roundtable on the Environment and Economy (2011) has recommended short-term actions for Canada to develop a national cap and trade program and to eventually link with a North American cap and trade system if the U.S. eventually develops and implements its own cap and trade system. However, as the Canadian federal government continues to seek to align its greenhouse gas regulations with those of the United States, it is unclear whether the Canadian federal government will pursue any short-term actions and therefore its regulations remain pending.

The Corporation believes that it is, and expects to continue to be, in material compliance with applicable environmental laws and regulations and is committed to meeting its responsibilities to protect the environment wherever it operates or holds working interests. The Corporation anticipates that this compliance may result in increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards.

See "*Risk Factors – The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities"* and *"Risk Factors – Government regulations and required regulatory approvals may adversely impact the Corporation's operations and result in increased operating and capital costs*".

WORKER SAFETY

Oilfield operations must be carried out in accordance with safe work procedures, rules and policies contained in applicable safety legislation. Such legislation requires that every employer ensures the health and safety of all persons at any of its work sites and all workers engaged in the work of that employer. The legislation, which provides for accident reporting procedures, also requires that every employer ensure that all of its employees are aware of their duties and responsibilities under the applicable legislation. Penalties under applicable occupational health and safety legislation include significant fines and incarceration.

Risk Factors

The following risk factors, together with other information contained in this Annual Information Form, should be carefully considered before investing in the Corporation. Each of these risks may negatively affect the trading price of the Common Shares or the amount of dividends that may, from time to time and at the discretion of the Corporation's board of directors, be declared and paid by the Corporation to its shareholders.

Low or volatile oil and natural gas prices could have a material adverse effect on the Corporation's results of operations and financial condition.

The Corporation's results of operations and financial condition are dependent on the prices it receives for the oil and natural gas it produces and sells. Oil and natural gas prices have fluctuated widely during recent years and may continue to be volatile in the future. Oil and natural gas prices may fluctuate in response to a variety of factors beyond the Corporation's control, including: (i) global energy supply, production and policies, including the ability of OPEC to set and maintain production levels in order to seek to influence prices for oil; (ii) political conditions, including the risk of hostilities in the Middle East and global terrorism; (iii) global and domestic economic conditions, including currency fluctuations; (iv) the level of consumer demand, including demand for different qualities and types of oil and liquids; (v) the production and storage levels of North American natural gas and the supply and price of imported oil and liquefied natural gas; (vi) weather conditions; (vii) the proximity of reserves and resources to, and capacity of, transportation facilities and the availability of refining capacity; (viii) the effect of world-wide energy conservation and greenhouse gas reduction measures and the price and availability of alternative fuels; and (ix) government regulations. Oil and natural gas producers in North America, and particularly Canada, currently receive significantly discounted prices for their production due to constraints on the ability to transport and sell such production to international markets. Additionally, limited natural gas processing capacity may result in producers not realizing the full price for liquids associated with their natural gas production. A failure to resolve such constraints may result in continued reduced commodity prices received by oil and natural gas producers such as the Corporation.

Any decline in crude oil or natural gas prices may have a material adverse effect on the Corporation's operations, financial condition, borrowing ability, levels of reserves and resources and the level of expenditures for the development of the Corporation's oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting the Corporation's production volumes.

The Corporation's expanding portfolio of growth-oriented projects in recent years may expose it to increased operational and financial risks.

As described under "*General Development of the Business*" and "*Business of the Corporation*", the Corporation has been adding more growth-oriented projects to its asset portfolio in recent years. These projects include Marcellus shale gas, North Dakota oil, early stage natural gas prospects, including the Duvernay and Wilrich, and undeveloped land positions in Alberta and Saskatchewan Bakken oil. These are earlier stage development projects (and, in certain cases, are more exploration-oriented in nature) than the Corporation has historically participated in and, as a result, there is more risk that the Corporation's expenditures on land, seismic and drilling may not provide economic returns. To the extent the Corporation acquires properties or assets with a higher exploration risk profile, the risk associated with such acquisitions and the future development of those assets carries similar risks.

Dividends on the Corporation's Common Shares are variable.

Although the Corporation currently intends to pay monthly cash dividends to its shareholders, these cash dividends may be reduced or suspended. The amount of cash available to the Corporation to pay dividends can vary significantly from period to period for a number of reasons, including among other things: (i) the Corporation's operational and financial performance (including fluctuations in the quantity of the Corporation's oil, NGLs and natural gas production and the sales price that the Corporation realizes for such production (after hedging contract receipts and payments)); (ii) fluctuations in the costs to produce oil, NGLs and natural gas, including royalty burdens, and to administer and manage the Corporation and its subsidiaries; (iii) the amount of cash required or retained for debt service or repayment; (iv) amounts required to fund capital expenditures and working capital requirements; (v) access to equity markets; (vi) foreign currency exchange rates and interest rates; and (vii) the risk factors set forth in this Annual Information Form. The decision whether or not to pay dividends and the amount of any such dividend is subject to the discretion of the board of directors of the Corporation, which regularly evaluates the Corporation's dividend policy and the solvency test requirements of the ABCA. In addition, the level of dividends per Common Share will be affected by the number of outstanding Common Shares and other securities that may be entitled to receive cash dividends or other payments. Dividends may be increased, reduced or suspended entirely depending on the Corporation's operations and the performance of its assets. The market value of the Common Shares may deteriorate if the Corporation is unable to meet dividend expectations in the future, and that deterioration may be material.

To the extent that the Corporation uses internally-generated cash flow to finance acquisitions, development costs and other significant capital expenditures, the amount of cash available to pay dividends to the Corporation's shareholders may be reduced. To the extent that external sources of capital, including debt or the issuance of additional Common Shares or other securities of the Corporation, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain, develop or expand its oil and gas reserves and resources and to invest in assets, as the case may be, will be impaired. To the extent that the Corporation is required to use cash flow to finance capital expenditures, property acquisitions or asset acquisitions, as the case may be, the level of the Corporation's cash dividend payments to its shareholders may be reduced or even eliminated.

The board of directors of the Corporation has the discretion to determine the extent to which the Corporation's cash flow will be allocated to the payment of debt service charges as well as the repayment of outstanding debt. The payments of interest and principal with respect to the Corporation's third party indebtedness, including the Credit Facilities, rank ahead of dividend payments that may be made by the Corporation to its shareholders. An increase in the amount of funds used to pay debt service charges or reduce debt will reduce the amount of cash that may be available for the Corporation to pay dividends to its shareholders. In addition, variations in interest rates and scheduled principal repayments, if and as required under the terms of the Credit Facilities, could result in significant changes in the amount required to be applied to debt service. Certain covenants in agreements with lenders may also limit payments of dividends.

The Corporation may require additional financing to maintain and expand its assets and operations.

In the normal course of making capital investments to maintain and expand the Corporation's oil, NGLs and natural gas reserves and resources, additional Common Shares or other securities of the Corporation may be issued, which may result in a decline in production per share and reserves and/or resources per share. Additionally, from time to time, the Corporation may issue Common Shares or other securities from treasury in order to reduce debt, complete acquisitions and maintain a more optimal capital structure. The Corporation may also dispose of existing properties or assets, including its equity holdings in other issuers, as a means of financing alternative projects or developments. To the extent that external sources of capital, including the availability of debt financing from banks or other creditors or the issuance of additional Common Shares or other securities, becomes limited, unavailable or available on less favourable terms, or if the Corporation is unable to dispose of its equity holdings as anticipated, the Corporation's ability to make the necessary capital investments to maintain or expand its oil, NGLs and natural gas reserves and resources will be impaired. To the extent that the Corporation is required to use additional cash flow to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of cash that may be available for the Corporation to pay dividends to its shareholders may be reduced.

The Corporation's Credit Facilities and any replacement credit facility may not provide sufficient liquidity.

Although the Corporation believes that its existing Credit Facilities are sufficient, there can be no assurance that the current amount will continue to be available or will be adequate for the financial obligations of the Corporation or that additional funds can be obtained as required or on terms which are economically advantageous to the Corporation. The amounts available under the Credit Facilities may not be sufficient for future operations, or the Corporation may not be able to renew its Bank Credit Facility or obtain additional financing on attractive economic terms, if at all. The Bank Credit Facility is generally available on a three year term, extendable each year with a bullet payment required at the end of three years if the facility is not renewed. The Corporation renewed its Bank Credit Facility in 2013, and accordingly it currently expires on October 31, 2016. There can be no assurance that such a renewal will be available on favourable terms or that all of the current lenders under the facility will renew at their current commitment levels. If this occurs, the Corporation may need to obtain alternate financing. Any failure of a member of the lending syndicate to fund its obligations under the Bank Credit Facility or to renew its commitment in respect of such Bank Credit Facility, or failure of the Corporation to obtain replacement financing or financing on favourable terms, may have a material adverse effect on the Corporation's business, and dividends to shareholders may be materially reduced or eliminated, as repayment of such debt has priority over dividend payments by the Corporation to its shareholders.

Additionally, in 2013 the Corporation made aggregate principal repayments on its Senior Unsecured Notes of US$45.8 million (CDN$64.6 million including underlying derivatives). The repayment of the Senior Unsecured Notes may require the Corporation to obtain additional financing, which may not be available or may be available on unfavourable terms. The repayment of the Senior Secured Notes also has priority over dividend payments to the Corporation's shareholders.

The Corporation's risk management activities could expose it to losses.

The Corporation may use financial derivative instruments and other hedging mechanisms to limit a portion of the adverse effects resulting from volatility in natural gas and oil commodity prices. To the extent the Corporation hedges its commodity price exposure, it may forego the benefits it would otherwise experience if commodity prices were to increase. In addition, the Corporation's commodity hedging activities could expose it to losses. These losses could occur under various circumstances, including if the other party to the Corporation's hedge does not perform its obligations under the hedge agreement. The Corporation has also entered into hedging arrangements to settle future payments under its equity-based long term incentive programs, which could result in the Corporation suffering losses to the extent the hedged costs of such arrangements exceed the actual costs that would otherwise be payable at the time of settlement.

Fluctuations in foreign currency exchange rates could adversely affect the Corporation's business.

The price that the Corporation receives for a majority of its oil and natural gas is based on U.S.- dollar denominated benchmarks and, therefore, the price that the Corporation receives in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the U.S. dollar may negatively impact the Corporation's net production revenue by decreasing the Canadian dollars the Corporation receives for a given sale in U.S. dollars while offering limited relief to the Corporation's cost structure, to the extent its costs are incurred in Canadian dollars. The Corporation conducts certain of its business and operations in the United States and is, therefore, exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. The Corporation may from time-to-time use derivative instruments to manage a portion of its foreign exchange risk. The Corporation currently has in place cross currency and foreign exchange swaps associated with certain of the Senior Unsecured Notes, as described in Note 8 to the Corporation's audited consolidated financial statements for the year ended December 31, 2013.

Lower oil and gas prices and higher costs increase the risk of write-downs of the Corporation's oil and gas property assets.

Under U.S. GAAP, the net capitalized cost of oil and gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer's fiscal year-end. The amount by which the net capitalized costs exceed the discounted value will be charged to net income. Generally speaking, and particularly in a declining commodity price environment, the use of the trailing twelve month average prices and discounting results in a greater likelihood of a ceiling test write-down under U.S. GAAP than IFRS. While these write-downs would not affect cash flow, the charge to earnings may be viewed unfavourably in the market.

The Corporation may be unable to add or develop additional reserves or resources.

The Corporation adds to its oil and natural gas reserves primarily through acquisitions and ongoing development of its existing reserves and resources, together with certain exploration activities. As a result, the level of the Corporation's future oil and natural gas reserves are highly dependent on its success in developing and exploiting its reserve and resource base and acquiring additional reserves and/or resources through purchases or exploration. Exploitation, exploration and development risks arise for the Corporation and, as a result, may affect the value of the Common Shares and dividends to shareholders due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. Additionally, if capital from external sources is not available or is not available on commercially advantageous terms, the Corporation's ability to make the necessary capital investments to maintain, develop or expand its oil and natural gas reserves and resources will be impaired. Even if the necessary capital is available, the Corporation cannot assure that it will be successful in acquiring additional reserves or resources on terms that meet its investment objectives. Without these additions, the Corporation's reserves will deplete and, as a consequence, either its production or the average life of its reserves will decline.

The Corporation's actual reserves and resources will vary from its reserve and resource estimates, and those variations could be material.

The value of the Common Shares depends upon, among other things, the reserves and resources attributable to the Corporation's properties. The actual reserves and resources contained in the Corporation's properties will vary from the estimates summarized in this Annual Information Form and those variations could be material. Estimates of reserves and resources are by necessity projections, and thus are inherently uncertain. The process of estimating reserves or resources requires interpretations and judgments on the part of petroleum engineers, resulting in imprecise determinations, particularly with respect to new discoveries. Different engineers may make different estimates of reserve or resource quantities and revenues attributable thereto based on the same data. Ultimately, actual reserves and resources attributable to the Corporation's properties will vary and be revised from current estimates, and those variations and revisions may be material. The reserve and resource information contained in this Annual Information Form is only an estimate. A number of factors are considered and a number of assumptions are made when estimating reserves and resources, such as, among other things: (i) historical production in the area compared with production rates from similar producing areas; (ii) future commodity prices, production and development costs, royalties and capital expenditures; (iii) initial production rates and production decline rates; (iv) ultimate recovery of reserves and resources and the success of future exploitation activities; (v) marketability of production; and (vi) the effects of government regulation and other government royalties or levies that may be imposed over the producing life of reserves and resources.

Reserve and resource estimates are based on the relevant factors, assumptions and prices on the date the evaluations were prepared. Many of these factors are subject to change and are beyond the Corporation's control. If these factors, assumptions and prices prove to be inaccurate, the Corporation's actual reserves and resources could vary materially from its estimates. Additionally, all such estimates are, to some degree, uncertain, and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable quantities of oil and natural gas, the classification of such reserves and resources based on risk of recovery and associated contingencies, and the estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric or probabilistic calculations and upon analogy to similar types of reserves or resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves or resources based upon production history may result in variations or revisions in the estimated reserves or resources, and any such variations or revisions could be material.

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil, natural gas and NGLs prices and operating costs. Market price fluctuations of commodity prices may render uneconomic the recovery of certain categories of petroleum or natural gas. Moreover, short-term factors may impair the economic viability of certain reserves or resources in any particular period.

The Corporation may not realize the anticipated benefits of its acquisitions or dispositions.

From time to time, the Corporation may acquire additional oil and natural gas properties and related assets. Achieving the anticipated benefits of such acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Corporation's ability to realize the anticipated growth opportunities and synergies from combining and integrating the acquired assets and properties into the Corporation's existing business. These activities will require the dedication of substantial management effort, time and capital and other resources, which may divert management's focus, capital and other resources from other strategic opportunities and operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Corporation's ability to achieve the anticipated benefits of future acquisitions. The risk factors set forth in this Annual Information Form relating to the oil and natural gas business and the operations, reserves and resources of the Corporation apply equally in respect of any future properties or assets that the Corporation may acquire. The Corporation generally conducts certain due diligence in connection with acquisitions, but there can be no assurance that the Corporation will identify all of the potential risks and liabilities related to the subject properties.

When acquiring assets, the Corporation is subject to inherent risks associated with predicting the future performance of those assets. The Corporation makes certain estimates and assumptions respecting the prospectivity and characteristics of the assets it acquires, which may not be realized over time. As such, assets acquired may not possess the value the Corporation attributed to them, which could adversely impact the Corporation's cash flows. To the extent that the Corporation makes acquisitions with higher growth potential, the higher risks often associated with such potential may result in increased chances that actual results may vary from the Corporation's initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches and assumptions than those of the Corporation's engineers, and these initial assessments may differ significantly from the Corporation's subsequent assessments.

Furthermore, potential investors should be aware that certain acquisitions, and in particular acquisitions of higher risk/higher growth assets, and the development of those acquired assets has required and will require significant capital expenditures from the Corporation, and the Corporation may not receive cash flow from operations from these acquisitions for several years or may receive cash flow in an amount less than anticipated. Accordingly, the timing and amount of capital expenditures may adversely affect the Corporation's cash flow.

The Corporation may also from time to time dispose of properties and assets. These dispositions may consist of non-core properties or assets or may consist of assets or properties that are being monetized in order to fund alternative projects or development by the Corporation. There can be no assurance that the Corporation will be successful in such dispositions or realize the amount of desired proceeds from such dispositions, or that such dispositions will be viewed positively by the financial markets, and such dispositions may negatively affect the Corporation's results of operations or the trading price of the Common Shares.

An increase in operating costs or a decline in the Corporation's production level could have a material adverse effect on results of operations and financial condition.

Higher operating costs for the Corporation's properties will directly decrease the amount of the Corporation's cash flow. Electricity, chemicals, supplies, energy services and labour costs are a few of the Corporation's operating costs that are susceptible to material fluctuation. The level of production from the Corporation's existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond the Corporation's control. Higher operating costs or a significant decline in production could result in materially lower cash flow and, therefore, could adversely affect the trading price of the Common Shares and reduce the amount that may be available for dividend payments by the Corporation to shareholders.

Since a portion of the Corporation's properties are not operated by the Corporation, results of operations may be adversely affected by the failure of third party operators.

The continuing production from a property, and to some extent the marketing of that production, is dependent upon the ability of the operators of the Corporation's properties. In 2013, approximately 33% of the Corporation's production was from properties operated by third parties. This results in significant reliance on third party operators in both the operation and development of such properties and control over capital expenditures relating thereto. The timing and amount of capital required to be spent by the Corporation may differ from the Corporation's expectations and planning, and may impact the ability and/or cost of the Corporation to finance such expenditures, as well as adversely affect other parts of the Corporation's business and operations. To the extent a third party operator fails to perform these duties properly, faces capital or liquidity constraints or becomes insolvent, the Corporation's results of operations will be negatively impacted.

Further, the operating agreements governing the properties not operated by the Corporation typically require the operator to conduct operations in a good and "workmanlike" manner. These operating agreements generally provide, however, that the operator has no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or wilful misconduct.

The Corporation is subject to risk of default by the counterparties to the Corporation's contracts.

The Corporation is subject to the risk that the counterparties to its risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to the Corporation's joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to the Corporation may adversely affect the results of operations, cash flows and financial position of the Corporation.

Delays in payment for business operations could adversely affect the Corporation.

In addition to the usual delays in payment by purchasers of oil and natural gas to the Corporation or to the operators of the Corporation's properties (and the delays of those operators in remitting payment to the Corporation), payments between any of these parties may also be delayed by, among other things: (i) capital or liquidity constraints experienced by such parties, including restrictions imposed by lenders; (ii) accounting delays or adjustments for prior periods; (iii) delays in the sale or delivery of products or delays in the connection of wells to a gathering system; (iv) weather related delays, such as freeze-offs, flooding and premature thawing; (v) blow-outs or other accidents; or (vi) recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of the Corporation's cash flow and the payment of cash dividends to its shareholders in a given period and expose the Corporation to additional third party credit risks.

The Corporation's operations are subject to certain risks and liabilities inherent in the oil and natural gas business, some of which may not be covered by insurance.

The Corporation's business and operations, including the drilling of oil and natural gas wells and the production and transportation of oil and natural gas, are subject to certain risks inherent in the oil and natural gas business. These risks and hazards include encountering unexpected formations or pressures, blow-outs, pipeline breaks, rail transportation incidents, craterings, fires, power interruptions and severe weather conditions. The Corporation's operations may also subject it to the risk of vandalism or terrorist threats, including eco-terrorism. The foregoing hazards could result in personal injury, loss of life, reduced production volumes or environmental and other damage to the Corporation's property and the property of others. The Corporation cannot fully protect against all of these risks, nor are all of these risks insurable. Although the Corporation carries liability, business interruption and property insurance in respect of such matters, there can be no assurance that insurance will be adequate to cover all losses resulting from such events or that the lost production will be restored in a timely manner. The Corporation may become liable for damages arising from these events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. While the Corporation has both safety and environmental policies in place to protect its operators and employees and to meet regulatory requirements in areas where they operate, any costs incurred to repair damages or pay liabilities would adversely affect the Corporation's financial position, including the amount of funds that may be available for dividend payments to shareholders.

In addition, the Corporation's unconventional oil and gas operations (such as the development and production of Bakken oil and shale gas) involve certain additional risks and uncertainties. The drilling and completion of wells and operations on these unconventional assets, and particularly in the Marcellus shale region, present certain challenges that differ from conventional oil and gas operations. Wells on these properties generally must be drilled deeper than in many other areas, which makes the wells more expensive to drill and complete. The wells may also be more susceptible to mechanical problems associated with the drilling and completion of the wells, such as casing collapse and lost equipment in the wellbore. In addition, the fracturing activities required to be undertaken on these unconventional assets may be more extensive and complicated than fracturing the geological formations in the Corporation's other areas of operation and require greater volumes of water than conventional wells. The management of water and the treatment of produced water from these wells may be more costly than the management of produced water from other geologic formations.

Unforeseen title defects, disputes or litigation may result in a loss of entitlement to production, reserves and resources.

From time to time, the Corporation conducts title reviews in accordance with industry practice prior to purchases of assets. However, if conducted, these reviews do not guarantee that an unforeseen defect in the chain of title will not arise and defeat the Corporation's title to the purchased assets. If this type of defect were to occur, the Corporation's entitlement to the production and reserves (and, if applicable, resources) from the purchased assets could be jeopardized. Furthermore, from time to time, the Corporation may have disputes with industry partners as to ownership rights of certain properties or resources, including with respect to the validity of oil and gas leases held by the Corporation or with respect to the calculation or deduction of royalties payable on the Corporation's production. The existence of title defects or the resolution of disputes may have a material adverse effect on the Corporation or its assets and operations. Furthermore, from time to time, the Corporation or its industry partners may owe one another a contractual, trust related or offset obligations which they may default in satisfying and which may adversely affect the validity of an oil and gas lease in which the Corporation has an interest. The existence of title defects, unsatisfied contractual or trust related obligations, including offset obligations, or the resolution of any disputes with industry partners arising from same, may have a material adverse effect on the Corporation or its assets and operations.

A decline in the Corporation's ability to market oil and natural gas production could have a material adverse effect on its production levels or on the price that the Corporation receives for production.

The Corporation's business depends in part upon the availability, proximity and capacity of oil and natural gas gathering systems, pipelines and rail transportation and processing facilities to provide access to markets for its production. Canadian federal and provincial, as well as U.S. federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, and changes in supply and demand could adversely affect the Corporation's ability to produce and market oil and natural gas. New resource plays generally experience a sharp increase in the amount of production being produced in the area, which could exceed the existing capacity of the various gathering, processing and pipeline infrastructure. For example, pipeline and transportation constraints experienced by oil producers in Montana and North Dakota have become more pronounced as a result of increased drilling and development activities in these regions. Additionally, as exploration and drilling on the Corporation's Marcellus shale gas properties increases, the amount of natural gas and associated NGLs being produced by the Corporation and others could exceed the capacity of the various gathering and intrastate or interstate transportation pipelines currently available in these areas. If these constraints remain unresolved, the Corporation's ability to transport its production in these regions may be impaired and could adversely impact the Corporation's production volumes or realized prices from these areas. Oil and natural gas producers in North America, and particularly Canada, currently receive significantly discounted prices for their production due to constraints on the ability to transport and sell such production to international markets. Also, limited natural gas processing capacity may result in producers not realizing the full price for liquids associated with their natural gas production. A failure to resolve such constraints may result in shut-in production or continued reduced commodity prices received by oil and natural gas producers such as the Corporation.

While the third party pipelines and railroad companies generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of pipeline and rail capacity, and unfavourable economic conditions or financing terms may defer or prevent the completion of certain pipeline projects or gathering systems or railway projects that are planned for such areas. There are also occasionally operational reasons, including as a result of maintenance activities, for curtailing transportation capacity. Accordingly, there can be periods where transportation capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. In such event, the Corporation may have to defer development of or shut in its wells awaiting a pipeline connection or other available transportation capacity and/or sell its production at lower prices than it would otherwise realize or than the Corporation currently projects, which would adversely affect the Corporation's results of and cash flow from operations.

Although the Corporation transports its crude oil production by a diverse mix of pipeline, rail and trucking transportation, in certain regions the Corporation is currently dependent upon only one means of transportation. There may be incremental costs associated with transporting crude oil by rail and there is a risk that access to rail transport may be constrained, dependent upon changes made to existing rail transport regulations. There is a potential for increased government regulations over transporting crude oil and natural gas liquids by rail in Canada and the United States. In addition, the assets of the Corporation are concentrated in specific regions with varying levels of government that could limit or ban the shipping of commodities by truck, pipeline or rail.

The Corporation may be unable to compete successfully with other organizations in the oil and natural gas industry.

The oil and natural gas industry is highly competitive. The Corporation competes for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of these organizations not only explore for, develop and produce oil and natural gas, but also conduct refining operations and market oil and other products on a world-wide basis. As a result of these complementary activities, some of the Corporation's competitors may have greater and more diverse competitive resources to draw upon.

Additionally, as the Corporation became subject to taxation as a Canadian corporation in 2011 as a result of the Conversion from an income trust to a corporation, the Corporation may be at a competitive disadvantage to other industry participants, such as pension resource corporations, U.S. flow-through entities, such as master limited partnerships and limited liability companies, and U.S. or other foreign corporations that are able to minimize Canadian tax through the use of inter-company debt, and cross-border tax planning measures or who have access to lower cost of capital.

The Corporation's operation of oil and natural gas wells could subject it to environmental costs, claims and liabilities.

GENERAL

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation in Canada and federal and state laws and regulations in the United States. A breach of that legislation may result in the imposition of fines or the issuance of "clean up" orders. Legislation regulating the Corporation's industry may be changed to impose higher standards and potentially more costly obligations, such as legislation that would require significant reductions in greenhouse gas emissions. See "*Industry Conditions – Environmental Regulation*" for a summary of certain proposals. Although the actual form such legislation or regulation may take is largely unknown at this time, the implementation of more stringent environmental legislation or regulatory requirements may result in additional costs for oil and natural gas producers such as the Corporation, and such costs may be significant.

The Corporation is not fully insured against certain environmental risks, either because such insurance is not available or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (as opposed to sudden and catastrophic damages) is not available on economically reasonable terms. Accordingly, the Corporation's properties may be subject to liability due to hazards that cannot be insured against, or that have not been insured against due to prohibitive premium costs or for other reasons.

The Corporation does not establish a separate reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations. The Corporation cannot assure investors that it will be able to satisfy its future environmental and reclamation obligations. Any site reclamation or abandonment costs incurred in the ordinary course, in a specific period, will be funded out of cash flows and, therefore, will reduce the amounts that may be available to pay as dividends to shareholders. Should the Corporation be unable to fully fund the cost of remedying an environmental claim, the Corporation might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy.

RISKS RELATING TO FRACTURING

The Corporation utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated drilling fluids and other technologies in connection with its drilling and completion activities. There has been public concern over the hydraulic fracturing process. Most of these concerns have raised questions regarding the drilling fluids used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations, the ability of such water to be recycled and induced seismicity associated with fracturing. The U.S. and Canadian federal governments and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in certain of the jurisdictions in which the Corporation operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. However, certain environmental and other groups have suggested that additional federal, provincial, territorial, state and municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process, and have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and may contribute to earthquake activity particularly where in proximity to pre-existing faults. In addition, the U.S. EPA has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impacts on drinking water sources and public health. Further, certain governments in jurisdictions where the Corporation does not currently operate have considered a temporary moratorium on hydraulic fracturing until further studies can be completed and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

It is anticipated that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While the Corporation is unable to predict the impact of any potential regulations upon its business, the implementation of new laws, regulations or permitting regulations with respect to water usage or hydraulic fracturing generally could increase the Corporation's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Corporation's production and prospects, any of which may have a material adverse effect on the Corporation's business, financial condition and results of operations.

The Corporation's expanded scope of activities and enlarged shareholder base may attract increased criticism and costly litigation.

The expansion of the Corporation's business activities, both geographically and with a new focus on exploration, may draw increased attention from special interest groups opposed to the Corporation, its business or its plans for development, which could have an adverse effect on market value. Higher visibility among investors may expose the Corporation to greater risk of class action lawsuits related to, among other things, securities, title and environmental matters.

Changes in tax and other laws and interpretations of those laws may adversely affect the Corporation and its securityholders.

Tax laws, including those that may affect the taxation of the Corporation or the Corporation's dividends to its shareholders, or other laws or government incentive programs relating to the oil and gas industry, may be changed or interpreted in a manner that adversely affects the Corporation and its securityholders. Additionally, tax authorities having jurisdiction over the Corporation (whether as a result of the Corporation's operations or financing structures) or its securityholders may change or interpret applicable tax laws or treaties or administrative positions in a manner which is detrimental to the Corporation or its securityholders, or may disagree with how the Corporation calculates its income for tax purposes. Additionally, the Corporation may be subject to additional taxation by the tribal authorities having jurisdiction over its Fort Berthold properties. The Corporation has income tax filings that are subject to audit and potential reassessment which may impact the Corporation's tax liability. The Corporation believes appropriate provisions for current and deferred income taxes have been made in its financial statements, however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of its tax liabilities and be detrimental to the Corporation.

Government regulations and required regulatory approvals and compliance may adversely impact the Corporation's operations and result in increased operating and capital costs.

The oil and gas industry operates under federal, provincial, state and municipal legislation and regulation governing such matters as royalties, land tenure, prices, production rates, environmental protection controls, well and facility design and operation, income, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, the imposition of specific drilling obligations, control over the development and abandonment of fields (including restrictions on production), and possibly expropriation or cancellation of contract rights. See "*Industry Conditions*". To the extent that the Corporation fails to comply with applicable government regulations or regulatory approvals, the Corporation may be subject to fines, enforcement proceedings (including "enforcement ladders" with varying penalties) and the restriction or complete revocation of rights to conduct its business, or to apply for regulatory approvals necessary to conduct its business, in the ordinary course.

Government regulations may be changed from time to time in response to economic or political conditions. Additionally, the Corporation's entry into new jurisdictions and its adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. For example, U.S. federal and state governments have increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures in the oil and gas industry, while cities such as Philadelphia and New York have called for bans on drilling in their local watersheds. Similarly, Canadian regulatory bodies have enhanced their oversight of and reporting obligations associated with fracturing procedures. More activity by the Corporation on Indian lands in North Dakota also may increase compliance obligations under local or tribal rules. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could negatively impact the development of oil and gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies, any of which could have a material adverse impact on the Corporation.

Additionally, various levels of Canadian and U.S. governments are considering legislation to reduce emissions of greenhouse gases. See "*Industry Conditions – Environmental Regulation*" for a description of these initiatives. Because the Corporation's operations emit various types of greenhouse gases, such new legislation or regulation could increase the costs related to operating and maintaining the Corporation's facilities and could require it to install new emission controls on its facilities, acquire allowances for its greenhouse gas emissions, pay taxes related to its greenhouse gas emissions and administer and manage a greenhouse gas emissions program. The Corporation is not able at this time to estimate such increased costs; however, they could be significant. Any of the foregoing could have adverse effects on the Corporation's business, financial position, results of operations and prospects.

The Corporation is required to assess its "foreign private issuer" status under U.S. securities laws on an annual basis at the end of its second quarter. If the Corporation were to lose its status as a "foreign private issuer" under U.S. securities laws and is required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country, it may incur additional general and administrative costs of compliance with the increased regulation under each regime.

If the Corporation expands beyond its current areas of operations or expands the scope of operations beyond oil and natural gas production, the Corporation may face new challenges and risks. If the Corporation is unsuccessful in managing these challenges and risks, its results of operations and financial condition could be adversely affected.

The Corporation may acquire oil and natural gas properties and assets outside the geographic areas in which it has historically conducted its business and operations. The expansion of the Corporation's activities into new locations may present challenges and risks that the Corporation has not faced in the past, including operational and additional regulatory matters. The Corporation's failure to manage these challenges and risks successfully may adversely affect results of operations and financial condition. In addition, the Corporation's activities are not limited to oil and natural gas production and development, and the Corporation could acquire other energy related assets. Expansion of the Corporation's activities into new areas may present challenges and risks that it has not faced in the past, including dealing with additional regulatory matters. If the Corporation does not manage these challenges and risks successfully, its results of operations and financial condition could be adversely affected.

The loss of the Corporation's key management and other personnel could impact its business.

Shareholders are entirely dependent on the management of the Corporation with respect to the exploration for and development of additional reserves and resources, the acquisition of oil and natural gas properties and assets and the management and administration of all matters relating to the Corporation and its properties and assets. The loss of the services of key individuals could have a detrimental effect on the Corporation. Further, the Corporation's acquisitions and activities in various play types require different skill sets than those needed in developing its mature income-oriented assets. There is no assurance that the Corporation will be able to attract and retain personnel with the technical expertise necessary to develop such properties, which could adversely affect the Corporation's exploration and development plans.

Conflicts of interest may arise between the Corporation and its directors and officers.

Circumstances may arise where directors and officers of the Corporation are directors or officers of corporations or other entities involved in the oil and gas industry which are in competition to the interests of the Corporation. See "*Directors and Officers – Conflicts of Interest*". No assurances can be given that opportunities identified by such persons will be provided to the Corporation.

Changes in market-based factors may adversely affect the trading price of the Common Shares.

The market price of the Common Shares is primarily a function of the value of the properties owned by the Corporation and anticipated dividends paid to its shareholders. The market price of the Common Shares is therefore sensitive to a variety of market-based factors, including, but not limited to, interest rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

The Corporation's information assets and critical infrastructure may be subject to destruction, theft, cyber-attacks or misuse by unauthorized parties.

The Corporation is subject to a variety of information technology and system risks as a part of its normal course operations. Although the Corporation has security measures in place that are designed to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and a disruption to its business activities. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

United States and other non-resident shareholders may be subject to additional taxation.

The Tax Act and the tax treaties between Canada and other countries may impose withholding or other taxes on the cash dividends, stock dividends or other property paid by the Corporation to shareholders who are not residents of Canada, and these taxes may change from time to time. In addition, the country in which the shareholder is resident may impose additional taxes on such dividends and these taxes may change from time to time.

Non-resident shareholders are subject to foreign exchange risk on the dividends that they may receive from the Corporation.

Any dividends that may be declared by the Corporation from time to time are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar weakens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

The ability of United States and other non-resident shareholder investors to enforce civil remedies may be limited.

The Corporation is formed under the laws of Alberta, Canada, and its principal place of business is in Canada. Most of the directors and officers of the Corporation are residents of Canada and some of the experts who provide services to the Corporation (such as its auditors and some of its independent reserve engineers) are residents of Canada, and all or a substantial portion of their assets and the Corporation's assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "**Foreign Jurisdiction**") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgments of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including U.S. federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against the Corporation or any of its directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of U.S. courts of liabilities based solely upon the U.S. federal securities laws or the securities laws of any state within the United States.

Market for Securities

The Common Shares are listed and posted for trading on the TSX and the NYSE under the trading symbol "ERF".

The following table sets forth certain trading information for the Common Shares on the TSX composite index and the United States composite index information for 2013.

	TSX Composite Trading			U.S. Composite Trading		
Month	**High**	**Low**	**Volume**	**High**	**Low**	**Volume**
January	$13.71	$12.86	15,221,416	US$13.80	US$13.04	16,762,962
February	$14.01	$12.26	19,404,765	US$13.74	US$12.03	20,008,692
March	$15.50	$13.85	23,643,782	US$15.17	US$13.42	17,355,247
April	$14.93	$12.93	20,546,858	US$14.71	US$12.60	21,020,438
May	$16.95	$13.89	20,660,684	US$16.47	US$13.76	23,054,130
June	$16.13	$14.30	14,214,208	US$15.60	US$13.57	15,772,686
July	$17.27	$15.29	16,913,079	US$16.75	US$14.43	13,828,054
August	$17.90	$16.75	14,419,227	US$17.37	US$16.06	12,166,659
September	$18.35	$17.05	13,574,869	US$17.69	US$16.58	11,083,681
October	$18.43	$16.15	20,145,290	US$17.61	US$15.53	12,863,732
November	$19.83	$17.33	17,792,523	US$18.75	US$16.58	16,712,644
December	$19.96	$18.96	17,520,616	US$18.79	US$17.82	12,103,691

Directors and Officers

DIRECTORS OF THE CORPORATION

The directors of the Corporation are elected by the shareholders of the Corporation at each annual meeting of shareholders. All directors serve until the next annual meeting or until a successor is elected or appointed or until the director is removed at a meeting of shareholders. The name, municipality of residence, year of appointment as a director of the Corporation (or its predecessor EnerMark Inc., the administrator of the Fund prior to the Conversion) and principal occupation for the past five years for each director of the Corporation are set forth below.

Name and Residence	Director Since	Principal Occupation for Past Five Years
David H. Barr(4)(6) Woodlands, Texas, United States	July 2011	Director of Logan International Inc., a TSX-listed company focused on downhole tools and completion services. Prior thereto, President and Chief Executive Officer and, prior thereto, the Chairman of the board of directors, of Logan International Inc., a TSX-listed oil and gas services company, since March 1, 2011. Prior thereto, Group President of various divisions of Baker Hughes Incorporated, an NYSE-listed oilfield services company.
Edwin V. Dodge(4)(6) Vancouver, British Columbia, Canada	May 2004	Corporate director.
Hilary A. Foulkes Calgary, Alberta, Canada	February 2014	Corporate Director. Prior thereto, Executive Vice President and Chief Operating Officer of Penn West Petroleum Ltd. from 2011 to 2012, a TSX and NYSE-listed oil and gas company. Prior thereto, Senior Vice President of Business Development of Penn West Petroleum Ltd. from 2008 to 2010.
James B. Fraser(5)(6) Polson, Montana, United States	June 2012	Corporate director since June 2012. Prior thereto, Senior Vice President for the shale division of Talisman Energy Inc.'s, a TSX and NYSE-listed oil and gas company, North American operations from September 2008 until April 2012.
Robert B. Hodgins(2)(3)(8) Calgary, Alberta, Canada	November 2007	Independent businessman.
Ian C. Dundas Calgary, Alberta, Canada	July 2013	President & Chief Executive Officer of Enerplus.
Susan M. MacKenzie(4)(5) Calgary, Alberta, Canada	July 2011	Independent consultant since September 2010. Prior thereto, Chief Operating Officer of Oilsands Quest Inc., an NYSE Amex-listed oil sands company through August 2010. Prior thereto, various senior managerial positions with Petro-Canada, a TSX and NYSE-listed integrated oil and gas company prior to its merger with Suncor Energy Inc. in 2009.
Donald J. Nelson(3)(4) Calgary, Alberta, Canada	June 2012	President of Fairway Resources Inc., a private oil and gas consulting services firm.
Douglas R. Martin(1) Calgary, Alberta, Canada	September 2000	Corporate director.
David P. O'Brien(3)(7) Calgary, Alberta, Canada	March 2008	Corporate director.
Elliott Pew(2)(5) Boerne, Texas, United States	September 2010	Director of Common Resources III, L.L.C., a private oil and gas company, since May 2010, and Southwestern Energy Company, an NYSE-listed oil and gas company since July 2012. Prior thereto, a director of Common Resources II, L.L.C., a private oil and gas company, from May 2010 to August 2012. Prior thereto, Chief Operating Officer of Common Resources L.L.C., a private oil and gas company, from March 2007 to May 2010.
Glen D. Roane(2)(3) Canmore, Alberta, Canada	June 2004	Corporate director.
Sheldon B. Steeves(2)(5) Calgary, Alberta, Canada	June 2012	Corporate Director. From January 2001 until April 2012, Chairman and Chief Executive Officer of Echoex Ltd., a junior private oil and gas company.

Notes:

(1) Chairman of the board of directors and ex officio member of all committees of the board of directors.
(2) The Audit & Risk Management Committee is currently comprised of Robert B. Hodgins as Chairman, Elliott Pew, Glen D. Roane and Sheldon B. Steeves.
(3) The Corporate Governance & Nominating Committee is currently comprised of Glen D. Roane as Chairman, Robert B. Hodgins, Donald J. Nelson and David P. O'Brien.

(4) The Compensation & Human Resources Committee is currently comprised of Susan M. MacKenzie as Chairman, David H. Barr, Edwin V. Dodge and Donald J. Nelson.
(5) The Reserves Committee is currently comprised of Elliott Pew as Chairman, James B. Fraser, Susan M. MacKenzie and Sheldon B. Steeves.
(6) The Safety & Social Responsibility Committee is currently comprised of Edwin V. Dodge as Chairman, David H. Barr and James B. Fraser.
(7) Mr. O'Brien is not standing for re-election at the 2014 annual meeting of shareholders of the Corporation.
(8) Mr. Hodgins was a director of Skope Energy Inc. ("**Skope**") in November 2012 when Skope entered into a settlement agreement with Pine Cliff Energy Ltd. ("**Pine Cliff**") and filed for protection under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**"). A plan for compromise and arrangement under the CCAA filed by Pine Cliff and Skope was accepted by the Court of Queen's Bench of Alberta on January 15, 2013, received the requisite approval of Skope's creditors on February 15, 2013 and came into effect on February 20, 2013. Mr. Hodgins resigned as a director of Skope on February 19, 2013.

OFFICERS OF THE CORPORATION

The name, municipality of residence, position held and principal occupation for the past five years for each officer of the Corporation are set out below.

Name and Residence	Office	Principal Occupation for Past Five Years
Ian C. Dundas Calgary, Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of the Corporation since July 1, 2013. Prior thereto, Executive Vice President & Chief Operating Officer of the Corporation since April 2011. Prior thereto, Executive Vice President, Enerplus since March 2010. Prior thereto, Senior Vice President, Business Development of Enerplus.
Robert J. Waters Calgary, Alberta, Canada	Senior Vice President & Chief Financial Officer	Senior Vice President & Chief Financial Officer of Enerplus.
Raymond J. Daniels Calgary, Alberta, Canada	Senior Vice President, Operations	Senior Vice President, Operations of the Corporation since May 2012. Prior thereto, Senior Vice President, Canadian Operations of the Corporation since April 2011. Prior thereto, Vice President, Development Services of Enerplus since July 2009. Prior thereto, Vice President, Oil Sands of Enerplus since December 2007.
Eric G. Le Dain Calgary, Alberta, Canada	Senior Vice President, Corporate Development, Commercial	Senior Vice President, Corporate Development, Commercial of the Corporation since July 2013. Prior thereto, Senior Vice President, Strategic Planning, Reserves & Marketing of the Corporation since April 2011. Prior thereto, Vice President, Strategic Planning, Reserves & Marketing of Enerplus since March 2010. Prior thereto, Vice President, Regulatory, Environment and Marketing of Enerplus since December 2008.
Jo-Anne M. Caza Calgary, Alberta, Canada	Vice President, Corporate & Investor Relations	Vice President, Corporate & Investor Relations of Enerplus since January 2008. Prior thereto, Vice President, Investor Relations since 2000.
Jodi Jenson Labrie Calgary, Alberta, Canada	Vice President, Finance	Vice President, Finance of the Corporation since July 2013. Prior thereto, Ms. Jenson Labrie held various positions of increasing responsibility since joining Enerplus in 2003, including Controller, Finance and Senior Manager Planning & Marketing.
Robert A. Kehrig Calgary, Alberta, Canada	Vice President, Business Development & New Plays	Vice President, Business Development & New Plays of the Corporation since February 2013. Prior thereto, Vice President, Resource Development of Enerplus since November 2008.
H. Gordon Love Calgary, Alberta, Canada	Vice President, Technical & Operations Services	Vice President, Technical & Operations Services of the Corporation since July 2012. Prior thereto, Senior Manager, Canadian Operations of the Corporation since May 2011, and, prior thereto, Manager of Well Services of Enerplus since August 2010. Prior to joining Enerplus, Vice President, Operations at Grey Wolf Exploration Inc., a TSX-listed oil and gas company prior to its acquisition by Insignia Energy Ltd. in 2009.
David A. McCoy Calgary, Alberta, Canada	Vice President, General Counsel & Corporate Secretary	Vice President, General Counsel & Corporate Secretary of Enerplus.
Edward L. McLaughlin Denver, Colorado, United States	President, U.S. Operations	President, U.S. Operations of Enerplus since May 2012. Prior thereto, Manager of Land of Enerplus USA since joining Enerplus in November 2011. Prior thereto, Vice President, Corporate Development of Venoco, Inc., an NYSE-listed energy company, from November 2010 to November 2011 and as Manager of Land of FIML Natural Resources, a U.S. private exploration and production company, from June to November 2010. Prior thereto, President of Petro-Canada Resources (USA) Inc., a U.S. subsidiary of Petro-Canada, a TSX and NYSE-listed oil and gas company prior to its merger with Suncor Energy Inc., from September 2003 to June 2010.

Christopher M. Stephens Calgary, Alberta, Canada	Vice President, Canadian Assets	Vice President, Canadian Assets of the Corporation since July 2012. Prior thereto, Senior Manager, Canadian Assets of the Corporation since May, and prior thereto, Business Unit Manager since June 2008. Prior thereto, Asset Manager at Burlington Resources Inc., an NYSE-listed oil and gas company prior to its acquisition by ConocoPhillips.
P. Scott Walsh Airdrie, Alberta, Canada	Vice President, Information & Corporate Services	Vice President, Information and Corporate Services of the Corporation since February 2014. Prior thereto, Vice President, Information Systems of the Corporation since April 2011. Prior thereto, Corporate Director, Information Services – Infrastructure and Application & Infrastructure with Suncor Energy Inc. Prior thereto, various management positions with Suncor Energy Inc.
Kenneth W. Young Calgary, Alberta, Canada	Vice President, Land	Vice President, Land of Enerplus since November 2008. Prior thereto, Vice President, Land at Avant Garde Energy Corp., a private oil and gas exploration and production company, since 2008.
Michael R. Politeski Calgary, Alberta, Canada	Treasurer & Corporate Controller	Treasurer & Corporate Controller of the Corporation since July 2013. Prior thereto, Controller, Finance of the Corporation since August 2012. Prior thereto, Manager Finance of Enerplus since June 2008.

COMMON SHARE OWNERSHIP

As of February 14, 2014, the directors and officers of the Corporation named above beneficially own, or control or exercise direction over, directly or indirectly, an aggregate of 302,639 Common Shares, representing approximately 0.15% of the outstanding Common Shares as of that date.

CONFLICTS OF INTEREST

Certain of the directors and officers named above may be directors or officers of issuers which are in competition with the Corporation, and as such may encounter conflicts of interests in the administration of their duties with respect to the Corporation. In situations where conflicts of interest arise, the Corporation expects the applicable director or officer to declare the conflict and, if a director of the Corporation, abstain from voting in respect of such matters on behalf of the Corporation.

See "*Risk Factors – Conflicts of interest may arise between the Corporation and its directors and officers*".

AUDIT & RISK MANAGEMENT COMMITTEE DISCLOSURE

The disclosure regarding the Corporation's Audit & Risk Management Committee required under National Instrument 52-110 adopted by the Canadian securities regulatory authorities is contained in Appendix D to this Annual Information Form.

Legal Proceedings and Regulatory Actions

The Corporation is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Corporation's favour, the Corporation does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Corporation may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operation or liquidity. The Corporation is not and was not during 2013 a party to, and none of the Corporation's property is or was during 2013 the subject of, any legal proceeding that involves a claim for damages (exclusive of interest and costs) greater than 10% of its current assets as at December 31, 2013, and the Corporation has no knowledge of any such proceeding being contemplated.

Interest of Management and Others in Material Transactions

To the knowledge of the directors and executive officers of the Corporation, none of the directors or executive officers of the Corporation and no person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of the Corporation's securities, nor any associate or affiliate of any of the foregoing, has had any material interest, direct or indirect, in any transaction with the Corporation since January 1, 2011 or in any proposed transaction that has materially affected or is reasonably expected to materially affect Enerplus.

Material Contracts and Documents Affecting the Rights of Securityholders

The Corporation is not a party to any contracts material to its business or operations, other than contracts entered into in the normal course of business.

Copies of the following documents entered into the normal course of business and relating to the Credit Facilities have been filed on the Fund's SEDAR profile at www.sedar.com and on Form 6-K on the Fund's EDGAR profile at www.sec.gov, if they were filed prior to the January 1, 2011 Conversion, and on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov, if they were filed on or after the January 1, 2011 Conversion:

1. Amended and Restated Bank Credit Facility (November 5, 2012) and the First Amending Agreement relating thereto (January 13, 2014);

2. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2002, together with the First Amendment and Second Amendment (March 18, 2008);

3. Third Amendment to the Note Purchase Agreement for the Senior Unsecured Notes issued in 2002 (SEDAR – November 10, 2010; EDGAR – November 12, 2010);

4. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2003, together with the First Amendment (March 18, 2008);

5. Second Amendment to the Note Purchase Agreement for the Senior Unsecured Notes issued in 2003 (SEDAR – November 10, 2010; EDGAR – November 12, 2010);

6. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2009 (SEDAR – June 23, 2009; EDGAR – June 25, 2009); and

7. Form of the Note Purchase Agreement for the Senior Unsecured Notes issued in 2012 (SEDAR – May 23, 2012; EDGAR – May 24, 2012).

Copies of the following documents affecting the rights of securityholders have been filed on the Corporation's SEDAR profile at www.sedar.com and on Form 6-K on the Corporation's EDGAR profile at www.sec.gov, as they were filed after the January 1, 2011 Conversion:

1. the Articles of Amalgamation (January 2, 2013) and bylaws of the Corporation (January 5, 2011); and

2. the Shareholder Rights Plan, as described under "*Description of Share Capital – Shareholder Rights Plan*" (May 10, 2013).

Interests of Experts

McDaniel prepared the McDaniel Reports in respect of certain reserves attributable to the Corporation's oil and natural gas properties in Canada and the western United States, a summary of which is contained in this Annual Information Form, and reviewed certain reserves evaluated internally by the Corporation. McDaniel also audited the estimate of contingent resources attributable to the Corporation's interests in the Fort Berthold, North Dakota area, which is referred to in this Annual Information Form. As of the dates of the McDaniel Reports, the "designated professionals" (as defined in Form 51-102F2 – *Annual Information Form* of the Canadian securities regulatory authorities) of McDaniel, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Common Shares. NSAI prepared the NSAI Reports in respect of the reserves and contingent resources attributable to the Corporation's interests in the Marcellus and Jonah properties, a summary of which is contained in this Annual Information Form. As of the dates of the NSAI Reports, the designated professionals of NSAI, as a group, beneficially owned, directly or indirectly, less than 1% of the outstanding Common Shares.

The independent auditor of the Corporation is Deloitte LLP ("**Deloitte**"), Independent Registered Chartered Accountants, Calgary, Canada. Deloitte has confirmed that it is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta, the rules of the United States Securities Act of 1933, as amended, and the applicable rules and regulations adopted by the U.S. Securities and Exchange Commission and the Public Company Accounting Oversight Board (United States).

Transfer Agent and Registrar

The transfer agent and registrar for the Common Shares in Canada is Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario. Computershare Trust Company N.A. at its principal offices in Golden, Colorado is the transfer agent for the Common Shares in the United States.

Additional Information

Additional information relating to the Corporation may be found on the Corporation's profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and on the Corporation's website at www.enerplus.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, as applicable, will be contained in the Corporation's information circular and proxy statement with respect to its 2014 annual meeting of shareholders. Furthermore, additional financial information relating to the Corporation is provided in the Corporation's audited consolidated financial statements and MD&A for the year ended December 31, 2013. Shareholders who wish to receive printed copies of these documents free of charge should contact the Corporation's Corporate & Investor Relations Department using the contact information on the final page of this Annual Information Form.

APPENDIX A

Appendix A – Reports on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

January 29, 2014

Enerplus Corporation
3000, 333 - 7th Avenue SW
Calgary, Alberta
T2P 2Z1

Attention: The Board of Directors of Enerplus Corporation

Re: **Form 51-101F2**

Report on Reserves Data by an Independent Qualified Reserves Evaluator of Enerplus Corporation

To the Board of Directors of Enerplus Corporation (the "Company"):

1. We have evaluated and reviewed the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation and review.

   We carried out our evaluation and review in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation and review also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated and reviewed by us, for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated, reviewed and reported on to the Company's management:

Preparation Date of Evaluation Report	**Location of Reserves**	**Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)**			
		Audited	**Evaluated**	**Reviewed**	**Total**
			(in $ thousands)		
January 29, 2014	Canada	–	$1,507,938.5	$522,061.5	$2,030,000.0
January 29, 2014	United States	–	US$1,999,491.6	US$ –	US$1,999,491.6

5. In our opinion, the reserves data respectively evaluated and reviewed by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

"*signed by P.A. Welch*"

P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
January 29, 2014

APPENDIX B

Appendix B – Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

To the board of directors of Enerplus Corporation (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2013, for certain properties located in Pennsylvania, West Virginia and Wyoming. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) Audited	Evaluated	Reviewed	Total
			(US$ thousands)			
Netherland, Sewell & Associates, Inc.	January 21, 2014	United States	Nil	$ 796,895.1	Nil	$ 796,895.1

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

NETHERLAND, SEWELL & ASSOCIATES, INC.
Texas Registered Engineering Firm F-2699
Dallas, Texas USA
February 12, 2014

"*signed by C.H. (Scott) Rees III*"

C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

APPENDIX C

Appendix C – Report of Management and Directors on Oil and Gas Disclosure

Terms to which a meaning is described in CSA Staff Notice 51-324 – Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities have the same meaning herein.

Management of Enerplus Corporation (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed the Corporation's reserves data. The reports of the independent qualified reserves evaluators are presented as Appendices A and B to this Annual Information Form.

The Reserves Committee of the board of directors of the Corporation has:

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors of the Corporation has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors of the Corporation has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Forms 51-101F2 which are the reports of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

ENERPLUS CORPORATION

"*Ian C. Dundas*"

Ian C. Dundas
President & Chief Executive Officer

"*Eric G. Le Dain*"

Eric G. Le Dain
Senior Vice President, Corporate Development, Commercial

"*Elliott Pew*"

Elliott Pew
Director

"*Sheldon B. Steeves*"

Sheldon B. Steeves
Director

February 21, 2014

APPENDIX D

Appendix D – Audit & Risk Management Committee Disclosure Pursuant to National Instrument 52-110

A. THE AUDIT & RISK MANAGEMENT COMMITTEE'S CHARTER

The charter of the Audit & Risk Management Committee (the "**Committee**") of the board of directors of the Corporation is attached as Schedule 1 to this Appendix D.

B. COMPOSITION OF THE AUDIT & RISK MANAGEMENT COMMITTEE

The current members of the Committee are Robert B. Hodgins (Chairman), Elliott Pew, Glen D. Roane and Sheldon B. Steeves. Each member of the Committee is independent and financially literate within the meaning of National Instrument 52-110.

C. RELEVANT EDUCATION AND EXPERIENCE

Name (Director Since)	Principal Occupation and Biography
Robert B. Hodgins (Honors B.A. (Business), C.A.) (Director since November 2007) Other Public Directorships • AltaGas Ltd. (energy midstream services) • Caracal Energy Inc. (oil and gas exploration and development company) • Contact Exploration Inc. (oil and gas exploration and production company) • Cub Energy Inc. (oil and gas exploration and production company) • MEG Energy Corp. (oil sands company) • MGM Energy Corp. (oil and gas exploration and production company) • Santonia Energy Inc. (oil and gas exploration and production company)	Mr. Hodgins has been an independent businessman since November 2004. Prior to that, Mr. Hodgins served as the Chief Financial Officer of Pengrowth Energy Trust (a TSX and NYSE-listed energy trust) from 2002 to 2004. Prior to that, Mr. Hodgins held the position of Vice President and Treasurer of Canadian Pacific Limited (a diversified energy, transportation and hotels company) from 1998 to 2002 and was Chief Financial Officer of TransCanada PipeLines Limited (a TSX and NYSE-listed energy transportation company) from 1993 to 1998. Mr. Hodgins received an Honors Bachelor of Arts in Business from the Richard Ivey School of Business at the University of Western Ontario in 1975 and received a Chartered Accountant designation and was admitted as a member of the Institute of Chartered Accountants of Ontario in 1977 and Alberta in 1991.
Mr. Elliott Pew (B.Sc., M.A.) (Director since September 2010) Other Public Directorships • Southwestern Energy Company (oil and gas exploration and production company)	Mr. Pew is a director of Common Resources II, LLC (a private oil and gas company) located in The Woodlands, Texas. Mr. Pew was a co-founder of Common Resources LLC and served as its Chief Operating Officer from March 2007 until it was sold in May 2010. Prior thereto, Mr. Pew was Executive Vice President, Exploration of Newfield Exploration Company (an NYSE-listed oil and gas company) from November 2004 to December 2006 where he led the company's diversification efforts onshore in the late 1990s in addition to leading the company's exploration program, including the formation of the deep water Gulf of Mexico business unit. Prior thereto, Mr. Pew was Senior Vice President, Exploration with American Exploration Corp. Mr. Pew is a Geology graduate of Franklin and Marshall College and holds an M.A. in Geology from the University of Texas.

Mr. Glen D. Roane (B.A., MBA) (Director since June 2004) Other Public Directorships • Badger Daylighting Ltd. (provider of non-destructive excavation services) • Logan International Inc. (oil and gas service business) • SilverWillow Energy Corporation (oil sands company)	Mr. Roane is a corporate director and has served as a board member of many TSX-listed companies including (in addition to those public entities listed herewith of which he currently serves as a director) UTS Energy Corporation, Repap Enterprises Inc., Ranchero Energy Inc., Forte Resources Inc., Valiant Energy Inc., Maxx Petroleum Ltd. and NQL Energy Services Inc., since his retirement from TD Asset Management Inc., a subsidiary of The Toronto-Dominion Bank (a publicly traded Canadian chartered bank) in 1997. In addition to serving as a director of the public entities listed herewith, Mr. Roane is a director of GBC North American Fund Inc., a Canadian mutual fund corporation. Mr. Roane is also a member of the Alberta Securities Commission. Mr. Roane holds a Bachelor of Arts and an MBA from Queen's University in Kingston, Ontario. Mr. Roane also holds the ICD.D designation from the Institute of Corporate Directors.
Mr. Sheldon B. Steeves (B.Sc. (Geology)) (Director since June 2012) Other Public Directorships • Tamarack Valley Energy Ltd.	Mr. Steeves has over 37 years of experience in the North American oil and gas industry and is currently a director of Tamarack Valley Energy Ltd., a TSX-listed Canadian oil and gas company with operations in the Western Canadian Sedimentary Basin. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a junior oil and gas private company focused on greenfield organic growth in Western Canada. Mr. Steeves spent over 15 years at Renaissance Energy Ltd., where he was appointed Chief Operating Officer in 1997. Mr. Steeves holds a Bachelor of Science in Geology from the University of Calgary.

D. PRE-APPROVAL POLICIES AND PROCEDURES

The Committee has implemented a policy restricting the services that may be provided by the Corporation's auditors and the fees paid to the Corporation's auditors. Prior to the engagement of the Corporation's auditors to perform both audit and non-audit services, the Committee pre-approves the provision of the services. In making their determination regarding non-audit services, the Committee considers the compliance with the policy and the provision of non-audit services in the context of avoiding impact on auditor independence. All audit and non-audit fees paid to Deloitte in 2013 and 2012 were pre-approved by the Committee. Based on the Committee's discussions with management and the independent auditors, the Committee is of the view that the provision of the non-audit services by Deloitte described above is compatible with maintaining that firm's independence from the Corporation.

E. EXTERNAL AUDITOR SERVICE FEES

The aggregate fees paid by the Corporation to Deloitte, Independent Registered Chartered Accountants, the independent auditor of Enerplus, for professional services rendered in Enerplus' last two fiscal years are as follows:

		2013		2012
		(in $ thousands)		
Audit fees(1)	$	**965.9**	$	809.9
Audit-related fees(2)		**–**		–
Tax fees(3)		**500.5**		678.9
All other fees(4)		**–**		–
	$	**1,466.4**	$	1,488.8

Notes:

(1) Audit fees were for professional services rendered by Deloitte for the audit of the Corporation's annual financial statements and reviews of the Corporation's quarterly financial statements, as well as services provided in connection with statutory and regulatory filings or engagements.
(2) Audit-related fees are for assurance and related services reasonably related to the performance of the audit or review of the Corporation's financial statements and not reported under "Audit fees" above.
(3) Tax fees were for tax compliance, tax advice and tax planning.
(4) All other fees are fees for products and services provided by the Corporation's auditors other than those described as "Audit fees", "Audit-related fees" and "Tax fees".

Audit & Risk Management Committee Charter

I AUTHORITY

The Audit & Risk Management Committee (the "Committee") of the Board of Directors (the "Board") of the Enerplus Corporation (the "Corporation") shall be comprised of three or more Directors as determined from time to time by resolution of the Board. Consistent with the appointment of other Board committees, the members of the Committee shall be elected by the Board at the first meeting of the Board following each annual meeting of Shareholders of the Corporation or at such other time as may be determined by the Board. The Chair of the Committee shall be designated by the Board, provided that if the Board does not so designate a Chair, the members of the Committee, by majority vote, may designate a Chair. The presence in person or by telephone of a majority of the Committee's members shall constitute a quorum for any meeting of the Committee. All actions of the Committee will require the vote of a majority of its members present at a meeting of the Committee at which a quorum is present.

Members of the Committee do not receive any compensation from the Corporation other than compensation as directors and committee members. Prohibited compensation includes fees paid, directly or indirectly, for services as consultant or as legal or financial advisor, regardless of the amount, but excludes any compensation approved by the Board and that is paid to the directors as members of the Board and its committees.

II PURPOSE OF THE COMMITTEE

The Committee's mandate is to assist the Board in fulfilling its oversight responsibilities with respect to:

1. financial reporting and continuous disclosure of the Corporation;

2. the Corporation's internal controls and policies, the certification process and compliance with regulatory requirements over financial matters;

3. evaluating and monitoring the performance and independence of the Corporation's external auditors; and

4. monitoring the manner in which the business risks of the Corporation are being identified and managed.

The Committee shall report to the Board on a regular basis with regard to such matters. The Committee has direct responsibility to recommend the appointment of the external auditors and approve their remuneration. The Committee may take such actions, as it deems necessary to satisfy itself that the Corporation's auditors are independent of management. It is the objective of the Committee to maintain free and open means of communications (including the annual proxy information circular) among the Board, the external auditors, and the financial senior management of the Corporation.

III COMPOSITION AND COMPETENCY OF THE COMMITTEE

Each member of the Committee shall be unrelated to the Corporation and, as such, shall be free from any relationship that may interfere with the exercise of his or her independent judgement as a member of the Committee. All members of the Committee shall be financially literate and at least one member of the Committee shall have accounting or related financial management expertise – "literate" or "literacy" and "expertise" as defined by applicable securities legislation. Members are encouraged to enhance their understanding of current issues through means of their preference.

IV MEETINGS OF THE COMMITTEE

The Committee shall meet with such frequency and at such intervals as it shall determine is necessary to carry out its duties and responsibilities. As part of its purpose to foster open communications, the Committee shall meet at least quarterly with management and the Corporation's external auditors in separate executive sessions to discuss any matters that the Committee or each of these groups, or persons, believes should be discussed privately. The Chair works with the Chief Financial Officer and external auditors to establish the agendas for Committee meetings, ensuring that each party's expectations are understood and addressed. The Committee, in its discretion, may ask members of management or others to attend its meetings (or portions thereof) and to provide pertinent information as necessary. The Committee shall maintain minutes of its meetings and records relating to those meetings and the Committee's activities and provide copies of such minutes to the Board.

V DUTIES AND ACTIVITIES OF THE COMMITTEE

Evaluating and monitoring the performance and independence of external auditors

1. Make recommendations to the Board on the appointment of external auditors of the Corporation;

2. Review and approve the Corporation's external auditors' annual engagement letter, including the proposed fees contained therein;

3. Review the performance of the external auditors and make recommendations to the Board regarding their replacement when circumstances warrant. The review shall take into consideration the evaluation made by management of the external auditors' performance and shall include.

    a) Review annually the external auditors' quality control, any material issues raised by the most recent quality control review, or peer review, of the firm, or any inquiry or investigation by governmental or professional authorities of the firm within the preceding five years, and any steps taken to deal with such issues;

    b) Obtain assurances from the external auditors that the audit was conducted in accordance with Canadian and U.S. generally accepted auditing standards; and

    c) Ensure that management interacts professionally with the auditors and confirm such behavior annually with both parties.

4. Oversee the independence of the external auditors by, among other things:

    a) requiring the external auditors to deliver to the Committee on a periodic basis a formal written statement detailing all relationships between the external auditors and the Corporation;

    b) reviewing and approving the Corporation's hiring policies regarding partners, employees and former partners and employees of current and former external auditors;

    c) actively engaging in a dialogue with the external auditors with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditors and recommending that the Board take appropriate action to satisfy itself of the auditors' independence.

    d) pre-approve the nature of non-audit related services and the fees thereon;

    e) conducting private sessions with the external auditors and encouraging direct communications between the Chair of the Committee and the audit partner;

    f) instructing the Corporation's external auditors that they are ultimately accountable to the Committee and the Board and that the Committee and the Board are responsible for the selection (subject to Shareholder approval), evaluation and termination of the Corporation's external auditors;

    g) having a private meeting with the external auditors at every quarterly Committee meeting; and

    h) obtaining annually the auditors' views on competency and integrity of the audit committee and senior financial executives;

Oversight of annual and quarterly financial statements, management discussion and analysis and press releases

5. Review and approve the annual audit plan of the external auditors, including the scope of audit activities, and monitor such plan's progress and results quarterly and at year end;

6. Confirm, through private discussions with the external auditors and management, that no restrictions are being placed on the scope of the external auditors' work;

7. Review the appropriateness of management's representation letter transmitted to the external auditors;

8. Receipt of certifications from the CEO and CFO;

9. Review with management the adequacy of annual and quarterly financial statements and disclosure in the management discussion and analysis and press release and recommend approval to the Board:

   a) obtain satisfactory answers from management following the review of the annual and quarterly financial statements and management discussion and analysis and press release;

   b) the qualitative judgments of the external auditors about the appropriateness, not just the acceptability, of accounting principles and financial disclosure practices used or proposed to be adopted by the Corporation and, particularly, their views about alternate accounting treatments and their effects on the financial results;

   c) the methods used to account for significant unusual transactions;

   d) the effect of significant accounting policies in controversial or emerging areas for which there is a lack of authoritative guidance or consensus;

   e) management's process for formulating sensitive accounting estimates and the reasonableness of these estimates;

   f) significant recorded and unrecorded audit adjustments;

   g) any material accounting issues among management and the external auditors;

   h) other matters required to be communicated to the Committee by the external auditors under generally accepted auditing standards;

   i) management's acknowledgement of its responsibility towards the financial statements;

   j) significant legal, compliance or regulatory matters that may have a material effect on the financial statements or the business of the organization (including material notices to, or inquiries received from, governmental agencies); and

   k) receive the report from the Reserves Committee over the appropriateness of reported reserves and resources.

Oversight of financial reporting process, internal controls, the continuous disclosure and certification process and compliance with regulatory requirements

10. Establishment of the Corporation's Whistleblower Policy for the submission, receipt, retention and treatment of complaints and concerns regarding accounting and auditing matters, and review any developments and responses on reports received thereunder;

11. Review the adequacy and effectiveness of the financial reporting system and internal control policies and procedures with the external auditors and management. Ensure that the Corporation complies with all new regulations in this regard;

12. Review with management the Corporation's internal controls, and evaluate whether the Corporation is operating in accordance with prescribed policies and procedures;

13. Review with management and the external auditors any reportable condition and material weaknesses affecting internal controls;

14. Review the management disclosure and oversight Committee's CEO and CFO certification processes to ensure compliance with U.S. and Canadian requirements.

15. Receive periodic reports from the external auditors and management to assess the impact of significant accounting or financial reporting developments proposed by the CICA, the AICPA, the Financial Accounting Standards Board, the SEC, the relevant Canadian securities commissions, stock exchanges or other regulatory body, or any other significant accounting or financial reporting related matters that may have a bearing on the Corporation;

16. Review annually the report of the external auditor on the Corporation's internal controls over financial reporting describing any material issues raised by the most recent reviews of internal controls and management information systems or by any inquiry or investigation by governmental or professional authorities and any recommendations made and steps taken to deal with any such issues;

Review of Business Risks

17. Review with management the process followed to do the Corporation's risk assessment and the policies to monitor, mitigate and report such business risks;

Other Matters

18. Review of appointment or dismissal of senior financial executives;

19. Conduct or authorize investigations into any matters within the Committee's scope of responsibilities, including retaining outside counsel or other consultants or experts for this purpose;

20. Review the disclosure made in the Annual Report, Annual Information Form, Form 40-F and the Information Circular regarding the Audit & Risk Management Committee;

21. Establish and maintain a free and open means of communication between the Board, the Committee, the external auditors, and management;

22. Perform such additional activities, and consider such other matters, within the scope of its responsibilities, as the Committee or the Board deems necessary or appropriate; and

23. Once a year, the Committee reviews the adequacy of its Charter and brings to the attention of the Board required changes, if any, for approval. The Committee is also reviewed annually by the Corporate Governance and Nominating Committee, which reports its findings to the Board.

While the Committee has the duties and responsibilities set forth in this Charter, the Committee is not responsible for planning or conducting the audit or for determining whether the Corporation's financial statements are complete and accurate and are in accordance with generally accepted accounting principles. Similarly, it is not the responsibility of the Committee to resolve disagreements, if any, between management and the external auditors. While it is acknowledged that the Committee is not legally obliged to ensure that the Corporation complies with all laws and regulations, the spirit and intent of this Charter is that the Committee shall take reasonable steps to encourage the Corporation to act in full compliance therewith.

APPENDIX E

Appendix E – Supplemental Information About Oil and Gas Producing Activities

The following disclosures including proved reserves, future net cash flows, and costs incurred attributable to Enerplus' crude oil and natural gas operations have been prepared in accordance with the provisions of the Financial Accounting Standards Board's Accounting Standards Update (ASU) No. 2010-03 "*Extractive Activities – Oil and Gas (Topic 932)* (the "**ASU**"). The standard requires the use of a 12 month average price to estimate proved reserves calculated as the unweighted arithmetic average of first-day-of-the-month prices within the 12 month period prior to the end of the reporting period. Proved reserves and production volumes are presented net of royalties in accordance with U.S. protocol.

A. PROVED OIL AND NATURAL GAS RESERVE QUANTITIES

Users of this information should be aware that the process of estimating quantities of "proved developed" and "proved undeveloped" crude oil, natural gas and natural gas liquids is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures. Future fluctuations in prices and costs, production rates, or changes in political or regulatory environments could cause the Corporation's reserves to be materially different from that presented.

Proved reserves, proved developed reserves and proved undeveloped reserves are defined under the ASU. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulation. Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The proved reserves disclosed herein are determined according to the definition of "proved reserves" under NI 51-101 which may differ from the definition provided in SEC rules, however the difference should not be material. See "*Presentation of Enerplus' Oil and Gas Reserves, Resources and Production Information*" in this Annual Information Form. All cost information in this section is stated in Canadian dollars and is calculated in accordance with United States of America Generally Accepted Accounting Principles ("**U.S. GAAP**").

Subsequent to December 31, 2013, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of proved reserves as of that date.

Enerplus' December 31, 2013 proved crude oil, natural gas and natural gas liquids reserves are located in western Canada, primarily in Alberta, British Columbia and Saskatchewan, as well as in the United States, primarily in the states of Montana, North Dakota, Pennsylvania, West

Virginia and Wyoming. Enerplus' net proved reserves summarized in the following chart represent the Corporation's lessor royalty, overriding royalty, and working interest share of reserves, after deduction of any Crown, freehold and overriding royalties:

	Canada		United States		Total	
	Oil and NGLs	**Natural Gas**	**Oil and NGLs**	**Natural Gas**	**Oil and NGLs**	**Natural Gas**
	(Mbbls)	(MMcf)	(Mbbls)	(MMcf)	(Mbbls)	(MMcf)
Proved Developed and Undeveloped Reserves at December 31, 2010	**74,069**	**389,353**	**24,770**	**78,032**	**98,839**	**467,385**
Purchases of reserves in place	101	–	–	–	101	–
Sales of reserves in place	(639)	(845)	(10)	(8,110)	(649)	(8,955)
Discoveries and extensions	3,617	14,016	9,627	44,988	13,244	59,004
Revisions of previous estimates	764	813	2,834	(3,310)	3,598	(2,497)
Improved recovery	203	2,715	–	–	203	2,715
Production	(6,810)	(70,498)	(3,335)	(9,820)	(10,145)	(80,318)
Proved Developed and Undeveloped Reserves at December 31, 2011	**71,305**	**335,554**	**33,886**	**101,780**	**105,191**	**437,334**
Purchases of reserves in place	1	–	2,871	5,232	2,872	5,232
Sales of reserves in place	(5,625)	(1,321)	(41)	(39)	(5,667)	(1,360)
Discoveries and extensions	2,396	1,545	9,172	44,357	11,568	45,902
Revisions of previous estimates	1,372	(77,050)	5,706	3,794	7,079	(73,256)
Improved recovery	51	350	–	–	51	350
Production	(7,247)	(65,072)	(4,825)	(15,991)	(12,072)	(81,063)
Proved Developed and Undeveloped Reserves at December 31, 2012	**62,253**	**194,005**	**46,769**	**139,133**	**109,022**	**333,139**
Purchases of reserves in place	1,472	1,482	25	92,395	1,497	93,877
Sales of reserves in place	(649)	(704)	–	–	(649)	(704)
Discoveries and extensions	2,617	9,944	4,174	140,142	6,791	150,086
Revisions of previous estimates	(4,025)	83,307	2,811	36,223	(1,214)	119,530
Improved recovery	–	–	–	–	–	–
Production	(6,198)	(56,760)	(6,199)	(33,114)	(12,397)	(89,874)
Proved Developed and Undeveloped Reserves at December 31, 2013	**55,470**	**231,274**	**47,580**	**374,779**	**103,050**	**606,053**
Proved Developed Reserves						
December 31, 2010	68,906	372,550	18,570	56,653	87,476	429,203
December 31, 2011	65,353	325,520	21,650	69,071	87,003	394,591
December 31, 2012	54,148	187,418	29,612	106,770	83,761	294,188
December 31, 2013	**47,316**	**225,005**	**33,147**	**265,464**	**80,463**	**490,469**

B. CAPITALIZED COSTS RELATED TO OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation, depletion and amortization, including impairments, relating to Enerplus' oil and gas exploration, development and producing activities are as follows:

	2013	2012	2011
		(in $ thousands)	
Capitalized costs[1]	**$ 11,481,207**	$ 10,658,923	$ 9,920,024
Less accumulated depletion, depreciation and amortization	**(9,061,063)**	(8,343,224)	(7,051,427)
Net capitalized costs	**$ 2,420,144**	$ 2,315,599	$ 2,868,597

Note:

(1) Includes capitalized costs of proved and unproved properties.

C. COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred in connection with oil and gas producing activities are presented in the table below. Property acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties, including an allocation of purchase price on business combinations that result in property acquisitions. A carry commitment relating to Enerplus' 2009 Marcellus acquisition was included in that years' property acquisition costs in its entirety and as a result property acquisition costs in subsequent years have excluded such carry commitment amounts satisfied during the year. Development costs include the costs of drilling and equipping development wells and facilities to extract, gather and store oil and gas, along with an allocation of overhead. Exploration costs include costs related to the discovery and the drilling and completion of exploratory wells in new crude oil and natural gas reservoirs. Asset retirement costs represent capitalized asset retirement costs during the year. No gains or losses on retirement activities were realized, due to settlements approximating the estimates.

	For the Year Ended December 31, 2013		
	Canada	**United States**	**Total**
		(in $ thousands)	
Acquisition of properties:			
Proved	**$ 34,632**	**$ 131,654**	**$ 166,286**
Unproved	**9,737**	**68,814**	**78,551**
Exploration costs	**27,312**	**4,481**	**31,793**
Development costs	**259,230**	**390,413**	**649,643**
Asset retirement costs	**31,536**	**5,097**	**36,633**
	$ 362,447	**$ 600,459**	**$ 962,906**

	For the Year Ended December 31, 2012		
	Canada	**United States**	**Total**
		(in $ thousands)	
Acquisition of properties:			
Proved	$ –	$ 117,625	$ 117,625
Unproved	13,581	17,131	30,712
Exploration costs	38,388	24,083	62,471
Development costs	216,968	574,016	790,984
Asset retirement costs	24,516	5,060	29,576
	$ 293,453	$ 737,915	$ 1,031,368

	For the Year Ended December 31, 2011		
	Canada	United States	Total
	(in $ thousands)		
Acquisition of properties:			
Proved	$ 2,100	$ –	$ 2,100
Unproved	110,382	33,173	143,555
Exploration costs	37,591	73,030	110,621
Development costs	288,669	467,203	755,872
Asset retirement costs	23,199	6,206	29,405
	$ 461,941	$ 579,612	$ 1,041,553

D. RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

The following table sets forth revenue and direct cost information relating to Enerplus' oil and gas producing activities for the years ended December 31, 2013, 2012 and 2011:

	For the Year Ended December 31, 2013		
	Canada	United States	Total
	(in $ thousands)		
Revenue			
Sales[(1)]	**$ 676,502**	**$ 675,970**	**$ 1,352,472**
Deduct[(2)]			
Production costs[(3)]	**293,339**	**160,400**	**453,739**
Depletion, depreciation, amortization and accretion	**300,464**	**292,739**	**593,203**
Current and deferred income tax provision (recovery)	**(21,787)**	**60,429**	**38,642**
Results of operations for oil and gas producing activities	**$ 104,486**	**$ 162,402**	**$ 266,888**

	For the Year Ended December 31, 2012		
	Canada	United States	Total
	(in $ thousands)		
Revenue			
Sales[(1)]	$ 707,985	$ 445,349	$ 1,153,334
Deduct[(2)]			
Production costs[(3)]	301,676	100,548	402,224
Depletion, depreciation, amortization, accretion and impairment	322,121	1,019,271	1,341,392
Current and deferred income tax provision (recovery)	15,646	(288,637)	(272,991)
Results of operations for oil and gas producing activities	$ 68,542	$ (385,833)	$ (317,291)

	For the Year Ended December 31, 2011		
	Canada	United States	Total
	(in $ thousands)		
Revenue			
Sales[1]	$ 824,213	$ 334,376	$ 1,158,589
Deduct[2]			
Production costs[3]	276,975	64,189	341,164
Depletion, depreciation, amortization, accretion and impairment	287,754	431,262	719,016
Current and deferred income tax provision (recovery)	258	(82,671)	(82,413)
Results of operations for oil and gas producing activities	$ 259,226	$ (78,404)	$ 180,822

Notes:

(1) Sales are presented net of royalties
(2) The costs deducted in this schedule exclude corporate overhead, interest expense and other costs which are not directly related to oil and gas producing activities.
(3) Production costs include operating costs, transportation costs and production taxes.

E. STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND NATURAL GAS RESERVE QUANTITIES

The following tables set forth the standardized measure of discounted future net cash flows from projected production of Enerplus' crude oil and natural gas reserves.

	As at December 31, 2013		
	Canada	United States	Total
	(in $ millions)		
Future cash inflows	**$ 5,078**	**$ 5,133**	**$ 10,212**
Future production costs	**2,297**	**1,614**	**3,911**
Future development and asset retirement costs	**495**	**606**	**1,100**
Future income tax expenses	**197**	**642**	**840**
Future net cash flows	**$ 2,088**	**$ 2,271**	**$ 4,360**
Deduction: 10% annual discount factor	**892**	**949**	**1,840**
Standardized measure of discounted future net cash flows	**$ 1,197**	**$ 1,323**	**$ 2,519**

	As at December 31, 2012		
	Canada	United States	Total
	(in $ millions)		
Future cash inflows	$ 5,196	$ 3,774	$ 8,970
Future production costs	2,233	846	3,079
Future development and asset retirement costs	510	683	1,193
Future income tax expenses	187	423	610
Future net cash flows	$ 2,267	$ 1,822	$ 4,090
Deduction: 10% annual discount factor	991	768	1,760
Standardized measure of discounted future net cash flows	$ 1,276	$ 1,054	$ 2,330

	As at December 31, 2011		
	Canada	United States	Total
	(in $ millions)		
Future cash inflows	$ 7,210	$ 3,141	$ 10,351
Future production costs	2,712	639	3,351
Future development and asset retirement costs	546	461	1,007
Future income tax expenses	525	685	1,210
Future net cash flows	$ 3,427	$ 1,357	$ 4,784
Deduction: 10% annual discount factor	1,473	600	2,073
Standardized measure of discounted future net cash flows	$ 1,954	$ 757	$ 2,711

F. CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND NATURAL GAS RESERVES

	2013	2012	2011
	(in $ millions)		
Beginning of year	**$ 2,330**	$ 2,711	$ 2,259
Sales of oil and natural gas produced, net of production costs	**(898)**	(754)	(814)
Net changes in sales prices and production costs	**217**	(1,050)	669
Changes in previously estimated development costs incurred during the period	**677**	842	830
Changes in estimated future development costs	**(572)**	(967)	(1,016)
Extension, discoveries and improved recovery, net of related costs	**515**	514	963
Purchase of reserves in place	**140**	88	2
Sales of reserves in place	**(163)**	(149)	(27)
Net change resulting from revisions in previous quantity estimates	**159**	480	(192)
Accretion of discount	**218**	283	215
Net change in income taxes	**(142)**	350	(165)
Other significant factors (Exchange rate)	**38**	(18)	(14)
End of year	**$ 2,519**	$ 2,330	$ 2,711

Enerplus Corporation

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Exhibit 99.2

REPORTS

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2013, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2013, has been audited by Deloitte LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2013.

Ian C. Dundas
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 20, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the internal control over financial reporting of Enerplus Corporation and subsidiaries (the "Company") as of December 31, 2013, based on the criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management's report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and our report dated February 20, 2014 expressed an unqualified opinion on those financial statements.

Deloitte LLP

Chartered Accountants

February 20, 2014
Calgary, Canada

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 20, 2014. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by Deloitte LLP, Independent Registered Chartered Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accounting Firm and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

Ian C. Dundas
President and
Chief Executive Officer

Robert J. Waters
Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 20, 2014

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Enerplus Corporation

We have audited the accompanying consolidated financial statements of Enerplus Corporation and subsidiaries (the "Company"), which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012, and the consolidated statements of income (loss) and comprehensive income (loss), consolidated statements of changes in shareholders' equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2013, and notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Enerplus Corporation and subsidiaries as at December 31, 2013 and December 31, 2012, and their financial performance and their cash flows for each of the years in the three-year period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control – Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte LLP

Chartered Accountants

February 20, 2014
Calgary, Canada

STATEMENTS

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2013	December 31, 2012
Assets			
Current assets			
Cash		$ 2,990	$ 5,200
Accounts receivable	3	165,091	161,131
Deferred income tax asset	13	48,476	–
Deferred financial assets	15	9,198	54,165
Other current assets		7,641	7,623
		233,396	228,119
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	2,420,144	2,315,599
Other capital assets, net	4	21,210	22,196
Property, plant and equipment		2,441,354	2,337,795
Goodwill		609,975	599,716
Deferred income tax asset	13	364,411	437,076
Deferred financial assets	15	19,274	8,013
Marketable securities	6	13,389	7,699
Total Assets		$ 3,681,799	$ 3,618,418
Liabilities			
Current liabilities			
Accounts payable	7	$ 377,157	$ 278,550
Dividends payable		18,250	17,882
Current portion of long-term debt	8	48,713	45,566
Deferred income tax liability	13	–	9,430
Deferred financial credits	15	37,031	18,522
		481,151	369,950
Long-term debt	8	976,585	1,023,999
Deferred financial credits	15	–	17,127
Asset retirement obligation	9	291,761	256,102
		1,268,346	1,297,228
Total Liabilities		1,749,497	1,667,178
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2013 – 203 million shares			
December 31, 2012 – 199 million shares	14	3,061,839	2,997,682
Paid-in capital	14	38,398	32,293
Accumulated deficit		(1,117,238)	(948,350)
Accumulated other comprehensive income/(loss)		(50,697)	(130,385)
		1,932,302	1,951,240
Total Liabilities & Equity		$ 3,681,799	$ 3,618,418
Commitments, Contingencies and Guarantees	16		

See accompanying notes to the Consolidated Financial Statements

Approved on behalf of the Board of Directors:

Douglas R. Martin
Director

Robert B. Hodgins
Director

Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

For the year ended December 31 (CDN$ thousands)	**Note**	**2013**	**2012**	**2011**
Revenues				
Oil and natural gas sales, net of royalties	10	$ 1,352,472	$ 1,153,334	$ 1,158,589
Commodity derivative instruments gain/(loss)	15	(41,870)	91,995	(27,092)
		1,310,602	1,245,329	1,131,497
Expenses				
Operating		343,433	319,031	280,425
Production taxes		70,388	56,624	40,092
Transportation		39,918	26,569	20,647
General and administrative	14	110,260	93,844	94,442
Depletion, depreciation, amortization and accretion		593,203	560,293	509,620
Asset impairment	5	–	781,099	209,396
Foreign exchange loss/(gain)	12	9,313	(17,204)	4,216
Interest	11	58,337	54,907	44,938
Other Income	6	(868)	(86,146)	(2,677)
		1,223,984	1,789,017	1,201,099
Income/(loss) before tax expense		86,618	(543,688)	(69,602)
Current income tax expense/(recovery)	13	7,889	1,648	81,195
Deferred income tax expense/(recovery)	13	30,753	(274,639)	(163,608)
Net Income/(loss)		$ 47,976	$ (270,697)	$ 12,811
Other Comprehensive Income/(loss)				
Changes due to marketable securities (net of tax)				
Unrealized gains/(losses)	6	7,136	(10,115)	685
Realized gains reclassified to net income	6	(315)	–	–
Change in cumulative translation adjustment		72,867	(32,255)	11,931
Other Comprehensive Income/(loss)		79,688	(42,370)	12,616
Total Comprehensive Income/(loss)		$ 127,664	$ (313,067)	$ 25,427
Net income/(loss) per share				
Basic	14	$ 0.24	$ (1.38)	$ 0.07
Diluted	14	$ 0.24	$ (1.38)	$ 0.07

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2013**	**2012**	**2011**
Share Capital			
Balance, beginning of year	$ 2,997,682	$ 2,622,003	$ 2,548,631
Public offering	–	330,618	–
Stock Option Plan – cash	14,838	1,180	11,626
Stock Option Plan – non cash	3,108	1,119	9,371
Dividend Reinvestment Plan	–	19,150	52,375
Stock Dividend Plan	46,211	23,612	–
Balance, end of year	$ 3,061,839	$ 2,997,682	$ 2,622,003
Paid-in Capital			
Balance, beginning of year	$ 32,293	$ 23,115	$ 20,156
Stock Option Plan – exercised	(3,108)	(1,119)	(9,371)
Stock Option Plan – expensed	9,213	10,297	12,330
Balance, end of year	$ 38,398	$ 32,293	$ 23,115
Accumulated Deficit			
Balance, beginning of year	$ (948,350)	$ (376,093)	$ –
Net income/(loss)	47,976	(270,697)	12,811
Dividends	(216,864)	(301,560)	(388,904)
Balance, end of year	$ (1,117,238)	$ (948,350)	$ (376,093)
Accumulated Other Comprehensive Income/(Loss)			
Balance, beginning of year	$ (130,385)	$ (88,015)	$ (100,631)
Changes due to marketable securities (net of tax)			
Unrealized gains/(losses)	7,136	(10,115)	685
Realized gains reclassified to net income	(315)	–	–
Change in cumulative translation adjustment	72,867	(32,255)	11,931
Balance, end of year	$ (50,697)	$ (130,385)	$ (88,015)
Total Shareholders' Equity	$ 1,932,302	$ 1,951,240	$ 2,181,010

See accompanying notes to the Consolidated Financial Statements

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	Note	2013	2012	2011
Operating Activities				
Net income/(loss)		$ 47,976	$ (270,697)	$ 12,811
Non-cash items add/(deduct):				
Depletion, depreciation, amortization and accretion		593,203	560,293	509,620
Asset impairment	5	–	781,099	209,396
Changes in fair value of derivative instruments	15	35,088	(85,163)	(31,920)
Deferred income tax expense/(recovery)	13	30,753	(274,639)	(163,608)
Foreign exchange (gain)/loss on debt and working capital	12	19,747	(7,647)	7,185
Share-based compensation – Stock Option Plan	14	9,213	10,297	12,330
Amortization of debt issue costs and senior note premium		793	(5)	(429)
Derivative settlement on senior notes principal repayment		17,827	18,406	19,119
Asset disposition (gain)/loss	6	(367)	(87,421)	(103)
Asset retirement obligation expenditures	9	(16,606)	(19,905)	(21,656)
Changes in non-cash operating working capital	18	28,851	(88,929)	71,487
Cash flow from operating activities		766,478	535,689	624,232
Financing Activities				
Proceeds from the issuance of shares	14	14,838	350,948	64,001
Cash dividends	14	(170,653)	(277,948)	(388,904)
Change in bank debt		(45,556)	(189,251)	212,732
Repayment of senior notes		(46,814)	(46,236)	(45,523)
Proceeds from senior note issue		–	406,088	–
Derivative settlement on senior notes principal repayment		(17,827)	(18,406)	(19,119)
Changes in non-cash financing working capital		368	(14,727)	451
Cash flow from financing activities		(265,644)	210,468	(176,362)
Investing Activities				
Capital expenditures		(687,905)	(865,296)	(877,767)
Property and land acquisitions		(244,837)	(185,337)	(255,209)
Property dispositions		365,135	245,771	641,190
Sale of marketable securities	6	2,482	146,898	1,544
Changes in non-cash investing working capital		60,604	(90,252)	38,592
Cash flow from investing activities		(504,521)	(748,216)	(451,650)
Effect of exchange rate changes on cash		1,477	1,630	1,035
Change in cash		(2,210)	(429)	(2,745)
Cash, beginning of year		5,200	5,629	8,374
Cash, end of year		$ 2,990	$ 5,200	$ 5,629

See accompanying notes to the Consolidated Financial Statements

NOTES

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

These annual audited Consolidated Financial Statements ("Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation ("The Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The Consolidated Financial Statements were authorized for issue by the Board of Directors on February 20, 2014.

2) SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements and, together with the following notes, are an integral part of the Consolidated Financial Statements.

a) Basis of Preparation

Enerplus' Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). These Consolidated Financial Statements present Enerplus' financial position as at December 31, 2013 and 2012 and results of operations for the years ended December 31, 2013, and the 2012 and 2011 comparative periods.

i. Functional and Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows, depreciation, depletion, amortization and accretion ("DDA&A"), impairment, asset retirement obligations, income taxes, contingent assets and liabilities, goodwill, share-based compensation and the fair value of derivative instruments. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

iii. Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled oil and natural gas assets are accounted for following the concept of undivided interest, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

The acquisition method of accounting is used to account for acquisitions of companies and assets that meet the definition of a business under U.S. GAAP. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

b) Revenue

Revenue associated with the sale of oil and natural gas is recognized when title passes from the Company to its customers if collectability is reasonably certain and the sales price is determinable. Revenue is measured at the fair value of the consideration received or receivable based on price, volumes delivered and contractual delivery points. Realized gains and losses from commodity price risk management activities are recognized in revenue when the contract is settled. Unrealized gains and losses on commodity price risk management activities are recognized in revenue based on the changes in fair value of the contracts at the end of the respective reporting period.

c) Oil and Natural Gas Properties

Enerplus uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs incurred in finding oil and natural gas reserves are capitalized, including general and administrative costs directly attributable to these activities. These costs are recorded on a country-by-country cost centre basis as oil and natural gas properties subject to depletion ("full cost pool"). Costs associated with production and general corporate activities are expensed as incurred.

The net carrying value of both proved and unproved oil and natural gas properties is depleted using the unit of production method, as determined using a constant price assumption of the simple average of the preceding twelve months' first-day-of-the-month commodity prices ("SEC prices"). The depletion calculation takes into account estimated future development costs necessary to bring those reserves into production.

Under full cost accounting, a ceiling test is performed on a cost centre basis. Enerplus limits capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and deferred income taxes, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties. If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher oil and natural gas prices subsequently increase the ceiling.

Proceeds on property dispositions are accounted for as a reduction to the full cost pool without recognition of a gain or loss, unless the deduction significantly alters the relationship between capitalized costs and proved reserves in the cost centre.

d) Other Capital Assets

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements and computer equipment. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

e) Goodwill

Enerplus recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Impairment testing is performed on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. If the fair value of the consolidated reporting unit is less than its book value (including goodwill), then goodwill is reduced to its implied fair value and the amount of the impairment is charged against earnings.

f) Asset Retirement Obligations

Enerplus' oil and natural gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future asset retirement obligation liability at each balance sheet date. The associated asset retirement cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability resulting from revisions to estimated timing of cash flows, or changes in the credit-adjusted risk-free rate are recognized as a change in the asset retirement obligation and related capitalized asset retirement cost.

Amortization of capitalized decommissioning costs and increases in asset retirement obligations resulting from the passage of time are recorded as amortization and accretion, respectively, which are included in depreciation, depletion, amortization and accretion and charged against net income.

g) Income Tax

Income tax expense is comprised of current and deferred income tax. Current income tax is the expected tax payable or refund on taxable income or loss for the year, using rates enacted at the reporting date. Deferred income tax is recognized using the liability method of accounting for income taxes. Under this method, deferred tax is recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted income tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax is recognized in net income except to the extent that it relates to items recognized directly in shareholders' equity. Deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. The Company routinely reviews deferred tax assets and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized.

The Company recognizes the financial statement effects of an uncertain tax position when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. The amount of tax benefit recognized is the largest amount of tax benefit that has a greater than 50 percent likelihood of being realized upon settlement with a taxation authority. The Company recognizes potential penalties and interest related to uncertain tax positions in income tax expense.

The effect of changes in enacted income tax rates or laws, for both current and deferred income tax, is recognized in net income in the period of enactment.

h) Financial Instruments

i. Fair Value Measurements

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Inputs used in determining the fair value are characterized according to the following fair value hierarchy:

Level 1 – Inputs represent quoted market prices in active markets for identical assets or liabilities, such as exchange traded commodity derivatives

Level 2 – Inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs

Level 3 – Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

Subsequent measurement is based on classification of the financial instrument into one of the following five categories: held-for-trading, held-to-maturity, available-for-sale, loans and receivables or other financial liabilities.

ii. Non-derivative financial instruments

Non-derivative financial instruments comprise cash, marketable securities, accounts receivable, accounts payable, dividends payable and debt. Cash is classified as held-for-trading and carried at cost, which approximates fair value due to the short-term nature of the instrument, based on a Level 1 designation. Accounts receivable are classified as loans and receivables and are carried at amortized cost less any allowance for impairment. Accounts payable, dividends payable and long-term debt are classified as other financial liabilities and are carried at amortized cost.

Enerplus holds certain marketable securities in entities involved in the oil and gas industry. These investments may include both publicly traded and unlisted marketable securities. Publicly traded investments are classified as available-for-sale and carried at fair value based on a Level 1 designation, with changes in fair value recorded in other comprehensive income. Fair values are determined by reference to quoted market bid prices at the close of business on the balance sheet date. Unlisted marketable securities are carried at cost. When investments are ultimately sold any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

Enerplus capitalizes transaction costs and premiums on long-term debt. These costs are amortized using the effective interest method.

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

Enerplus' physical delivery purchase and sales contracts qualify as normal purchases and sales as they are entered into and held for the purpose of receipt or delivery of products in accordance with the Company's expected purchase, sale or usage requirements. As such, these contracts are not considered derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

i) Foreign Currency

i. Foreign currency transactions

Transactions denominated in foreign currencies are translated to Canadian dollars using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

ii. Foreign operations

Assets and liabilities of Enerplus' U.S. operations are translated into Canadian dollars at period end exchange rates while revenues are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment ("CTA") which is recorded in accumulated other comprehensive income ("AOCI").

j) Share-Based Compensation

Enerplus' share-based compensation plans include its Stock Option Plan and long-term incentive plans.

Under Enerplus' Stock Option Plan, employees are granted options to purchase common shares of the Company at an exercise price equal to the market value of the common shares on the date the options are granted. Options granted are exercisable in thirds over the three year vesting schedule and expire seven years after the date the options are granted. Enerplus uses the Black-Scholes option pricing model to calculate the grant date fair value of stock options granted under the Company's Stock Option Plan. This amount is charged to earnings as share-based compensation over the vesting period of the options, with a corresponding increase in paid-in capital. When options are exercised, the proceeds, together with the amount recorded in paid-in capital, are recorded to share capital. The Company is authorized to issue up to 10% of outstanding common shares from treasury as options are exercised.

Enerplus' long-term incentive plans include its Restricted Share Unit ("RSU"), Performance Share Unit ("PSU") and Director Share Unit ("DSU") plans. Under Enerplus' RSU plan, employees receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. Upon vesting, the plan participants receive a cash payment based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

Under Enerplus' PSU plan, executives and management receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. Upon vesting, the plan participants receive a cash payment based on the value of the underlying shares plus notional accrued dividends. The payment is subject to a multiplier that ranges from 0 to 2.0 depending on Enerplus' performance compared to the TSX oil and gas index over the vesting period.

Under Enerplus' DSU plan, directors receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual non-cash retainer value and they vest upon the director leaving the Board. Upon vesting, the plan participants receive a cash payment based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

Enerplus recognizes a liability for its long-term incentive plans based on their estimated fair value which is determined using the current market price of the Company's shares, accumulated dividends, and estimated performance multipliers, where applicable. The liability is re-measured at each reporting date and on the settlement date with any changes in fair value recorded as share-based compensation, which is included in general and administrative expenses.

k) Net Income Per Share

Basic net income per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options would be used to repurchase common shares at the average market price.

l) Contingencies

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

m) Recent Pronouncements Issued

As of January 1, 2014 Enerplus will adopt the following FASB accounting standards updates, which have been issued but are not yet effective. The adoption of these standards is not expected to have any material impact on Enerplus' financial statements.

- Accounting Standards Update 2013-04, *Obligations resulting from Joint and Several Liability Arrangements*
- Accounting Standards Update 2013-05, *Parent's Accounting for Cumulative Translation Adjustments upon Derecognition of Certain Subsidiaries*
- Accounting Standards Update 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*

3) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2013	December 31, 2012
Accrued receivables	$ 122,482	$ 107,518
Accounts receivable – trade	36,034	45,657
Current income tax receivable	9,371	10,759
Allowance for doubtful accounts	(2,796)	(2,803)
Total accounts receivable	$ 165,091	$ 161,131

4) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

As at December 31, 2013 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 11,481,207	$ 9,061,063	$ 2,420,144
Other capital assets	89,818	68,608	21,210
Total PP&E	$ 11,571,025	$ 9,129,671	$ 2,441,354

As at December 31, 2012 ($ thousands)		Cost		Accumulated Depletion and Depreciation		Net Book Value
Oil and natural gas properties	$	10,658,923	$	8,343,324	$	2,315,599
Other capital assets		82,587		60,391		22,196
Total PP&E	$	10,741,510	$	8,403,715	$	2,337,795

5) IMPAIRMENT

($ thousands)		2013		2012		2011
Oil and natural gas properties	$	–	$	781,099	$	209,396
Impairment expense	$	–	$	781,099	$	209,396

Enerplus did not record any ceiling test impairments on its oil and natural gas properties in 2013. During 2012 and 2011, non-cash impairments totaling $781.1 million and $209.4 million, respectively, were recorded in the United States cost centre due to continued capital spending and declines in the 12-month average trailing natural gas price during 2012. No impairments were recorded to the Canadian cost centre in the comparative periods.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2013, 2012 and 2011:

Year		WTI Crude Oil US$/bbl		Exchange Rate US$/CDN$		Edm Light Crude CDN$/bbl		U.S. Henry Hub Gas US$/Mcf		AECO Natural Gas Spot CDN$/Mcf
2013	$	96.94	$	1.03	$	93.19	$	3.67	$	3.16
2012		94.71		1.00		88.33		2.83		2.35
2011		96.19		0.98		97.30		4.18		3.75

6) MARKETABLE SECURITIES

During the year ended December 31, 2013 Enerplus sold certain publicly traded securities for proceeds of $2.5 million recognizing a gain of $0.4 million. In connection with these sales, realized gains of $0.3 million net of tax were reclassified from accumulated other comprehensive income to net income.

During the year ended December 31, 2012 Enerplus sold the majority of its unlisted securities, including its Laricina shares which were sold for proceeds of $141.0 million and a gain of $86.5 million.

For the year ended December 31, 2013 the change in fair value of publicly listed investments represented unrealized gains of $7.1 million net of tax ($8.2 million before tax). For the year ended December 31, 2012 and 2011 the change in fair value of these investments represented unrealized losses of $10.1 million ($11.9 million before tax) and unrealized gains of $0.7 million ($0.9 million before tax), respectively.

Realized gains are included in Other Income on the Consolidated Income Statements.

7) ACCOUNTS PAYABLE

($ thousands)		December 31, 2013		December 31, 2012
Accrued payables	$	262,117	$	184,498
Accounts payable – trade		115,040		94,052
Total accounts payable	$	377,157	$	278,550

8) DEBT

($ thousands)		December 31, 2013		December 31, 2012
Current:				
Senior notes	$	48,713	$	45,566
		48,713		45,566
Long-term:				
Bank credit facility	$	214,394	$	260,950
Senior notes		762,191		763,049
		976,585		1,023,999
Total debt	$	1,025,298	$	1,069,565

Bank Credit Facility

Enerplus has an unsecured, covenant-based, $1 billion bank credit facility that matures on October 31, 2016. Drawn fees range between 150 and 315 basis points over bankers' acceptance rates, with current drawn fees of 170 basis points. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility each year or repay the entire balance at the end of the term. At December 31, 2013 Enerplus had $214.4 million drawn and was in compliance with all financial covenants under the facility. During 2013 a fee of $0.7 million was paid to extend the facility. These fees are considered debt issue costs and are capitalized on the Consolidated Balance Sheets. The weighted average interest rate on the facility for the year ended December 31, 2013 was 2.6% (December 31, 2012 – 2.4%).

Senior Notes

On June 19, 2013 Enerplus made its fourth principal repayment on the US$175.0 million senior notes and associated cross currency interest rate swap principal settlement for a total of $53.7 million. On October 1, 2013 Enerplus made its third principal repayment and associated foreign exchange swap settlement on the US$54.0 million senior notes for a total of $10.9 million.

The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)		CDN$ Carrying Value ($ thousands)
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	$	30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000		21,272
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$355,000		377,578
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.37%	CDN$40,000	CDN$40,000		40,000
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.82%	US$40,000	US$40,000		42,544
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$225,000		239,310
Oct 1, 2003	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011	5.46%	US$54,000	US$21,600		22,974
June 19, 2002	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010	6.62%	US$175,000	US$35,000		37,226
				Total carrying value		$	810,904
				Current portion		$	48,713
				Long-term portion		$	762,191

9) ASSET RETIREMENT OBLIGATION

At December 31, 2013 Enerplus estimated the present value of its asset retirement obligation to be $291.8 million (December 31, 2012 – $256.1 million) based on a total undiscounted liability of $720.6 million (December 31, 2012 – $659.7 million). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.96% at December 31, 2013 (December 31, 2012 – 6.15%). Enerplus' asset retirement obligation expenditures are expected to be incurred over the next 66 years with the majority between 2024 and 2053. The change in capitalized asset retirement costs for the year ended December 31, 2013 was $37.3 million (December 31, 2012 – $29.5 million).

($ thousands)	December 31, 2013	December 31, 2012
Balance, beginning of year	$ 256,102	$ 232,139
Change in estimates	44,217	40,843
Property acquisition and development activity	1,454	1,395
Dispositions	(8,362)	(12,721)
Settlements	(16,606)	(19,905)
Accretion expense	14,956	14,351
Balance, end of year	$ 291,761	$ 256,102

10) OIL AND NATURAL GAS SALES

($ thousands)	2013	2012	2011
Oil and natural gas sales	$ 1,616,798	$ 1,365,542	$ 1,363,727
Royalties(1)	(264,326)	(212,208)	(205,138)
Oil and natural gas sales, net of royalties	$ 1,352,472	$ 1,153,334	$ 1,158,589

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Income Statement.

11) INTEREST EXPENSE

($ thousands)	2013	2012	2011
Realized:			
Interest on bank debt and senior notes	$ 56,716	$ 53,074	$ 47,049
Unrealized:			
Cross currency interest rate swap (gain)/loss	1,306	2,963	355
Interest rate swap (gain)/loss	(478)	(1,125)	(2,037)
Amortization of debt issue costs and senior note premium	793	(5)	(429)
Interest expense	$ 58,337	$ 54,907	$ 44,938

12) FOREIGN EXCHANGE

($ thousands)	2013	2012	2011
Realized:			
Foreign exchange (gain)/loss	$ 17,596	$ 6,508	$ 18,421
Unrealized:			
Translation of U.S. dollar debt and working capital	19,747	(7,647)	7,185
Cross currency interest rate swap (gain)/loss	(19,920)	(15,118)	(15,133)
Foreign exchange swap (gain)/loss	(8,110)	(947)	(6,257)
Foreign exchange (gain)/loss	$ 9,313	$ (17,204)	$ 4,216

13) INCOME TAXES

For the year ended December 31, ($ thousands)	2013	2012	2011
Current Tax			
Canada	$ (621)	$ (2,074)	$ 569
United States	8,510	3,722	80,626
Current tax expense/(recovery)	7,889	1,648	81,195
Deferred Tax			
Canada	$ (21,166)	$ 17,720	$ (311)
United States	51,919	(292,359)	(163,297)
Deferred tax expense/(recovery)	30,753	(274,639)	(163,608)
Income tax expense/(recovery)	$ 38,642	$ (272,991)	$ (82,413)

Deferred income tax expense recognized in Other Comprehensive Income totaled $1.0 million for 2013 ($3.0 million recovery in 2012, and $0.1 million expense in 2011) related to marketable securities.

The following provides a reconciliation of income taxes calculated at the Canadian statutory rate to the actual income taxes:

($ thousands)	2013	2012	2011
Income/(loss) before taxes			
Canada	$ (74,946)	$ 220,259	$ 113,712
United States	161,564	(763,947)	(183,314)
Total income/(loss) before taxes	$ 86,618	$ (543,688)	$ (69,602)
Canadian statutory rate	25.35%	25.32%	26.82%
Expected income tax expense/(recovery)	$ 21,958	$ (137,662)	$ (18,667)
Impact on taxes resulting from:			
Foreign tax rate differential	$ 10,407	$ (106,858)	$ (35,440)
Statutory and other rate differences	(1,976)	(7,828)	(28,923)
Recognition of previously unrecognized deferred tax assets	(690)	(11,082)	(3,970)
Non-taxable capital (gains)/losses	4,884	(12,248)	(364)
Share-based compensation	2,335	2,574	3,307
Other	1,724	113	1,644
Income tax expense/(recovery)	$ 38,642	$ (272,991)	$ (82,413)

Deferred income tax asset (liability) consists of the following temporary differences:

($ thousands)	2013	2012
Deferred income tax liabilities		
Property, plant and equipment	$ (62,565)	$ (11,473)
Long-Term debt	(2,154)	(10,825)
Deferred financial assets and credits	–	(10,320)
Other	(7,189)	–
Total deferred income tax liabilities	(71,908)	(32,618)
Deferred income tax assets		
Tax loss carryforwards and other credits	$ 551,331	$ 541,694
Asset retirement obligation	75,677	65,858
Deferred financial assets and credits	2,114	–
Marketable Securities	1,620	2,688
Other	6,697	4,128
Total deferred income tax assets	637,439	614,368
Less valuation allowance	(152,644)	(154,104)
Total deferred income tax assets, net	484,795	460,264
Net deferred income tax asset/(liability)	$ 412,887	$ 427,646

The net deferred income tax asset includes a current deferred income tax asset of $48.5 million (December 31, 2012 – liability of $9.4 million) and a long-term deferred income tax asset of $364.4 million (December 31, 2012 – $437.1 million).

Loss carryforwards and tax credits that can be utilized in future years are as follows:

As at December 31 ($ thousands)	**2013**	**Expiration Date**
Canada		
Capital losses	$ 1,208,000	Indefinite
Non-capital losses	445,000	2028-2031
United States		
Net operating losses	463,000	2030-2033
Alternative minimum tax credits	99,000	Indefinite

Changes in the balance of Enerplus' unrecognized tax benefits are as follows:

For the years ended December 31 ($ thousands)	**2013**	**2012**	**2011**
Balance, beginning of year	$ 18,500	$ 13,600	$ 13,200
Increase/(decrease) for tax positions of prior years	(500)	4,900	1,000
Lapse of statute of limitations	–	–	(600)
Balance, end of year	$ 18,000	$ 18,500	$ 13,600

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2013 would affect Enerplus' effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

Enerplus recognizes accrued interest in respect of unrecognized tax benefits in income tax expense. During 2013, Enerplus recognized an interest recovery of $0.1 million (2012 – expense of $0.3 million; 2011 – expense of $1.5 million). As at December 31, 2013 Enerplus had a liability of $0.2 million (December 31, 2012 – $0.3 million) for interest accrued related to unrecognized tax benefits.

A summary of the taxation years, by jurisdiction, that remain subject to examination by the taxation authorities are as follows:

Jurisdiction	Taxation Years
Canada – Federal & Provincial	2004-2013
United States – Federal & State	2008-2013

Enerplus' group of companies files income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

14) SHAREHOLDERS' EQUITY

a) Share Capital

	2013			2012			2011		
Authorized unlimited number of common shares Issued: (thousands)	**Shares**		**Amount**	**Shares**		**Amount**	**Shares**		**Amount**
Balance, beginning of year	198,684	$	2,997,682	181,159	$	2,622,003	178,649	$	2,548,631
Issued for cash:									
Public offerings	–		–	14,709		330,618	–		–
Dividend Reinvestment Plan	–		–	955		19,150	1,928		52,375
Stock Option Plan	1,042		14,838	68		1,180	582		11,626
Non-cash:									
Stock Dividend Plan	3,032		46,211	1,793		23,612	–		–
Stock Option Plan			3,108	–		1,119	–		9,371
Balance, end of year	202,758	$	3,061,839	198,684	$	2,997,682	181,159	$	2,622,003

The Company is authorized to issue an unlimited number of common shares without par value.

b) Dividends

($ thousands)		2013		2012		2011
Cash dividends[(1)]	$	170,653	$	277,948	$	388,904
Stock Dividend Plan		46,211		23,612		–
Dividends to shareholders	$	216,864	$	301,560	$	388,904

(1) Includes $19.2 million in 2012 and $52.4 million in 2011 related to the former Dividend Reinvestment Plan.

For the year ended December 31, 2013 Enerplus paid dividends of $1.08 per common share totaling $216.9 million (December 31, 2012 – $1.54 per share and $301.6 million, December 31, 2011 – $2.16 per share and $388.9 million).

c) Share-based compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in General and Administrative expense on the Consolidated Income Statements:

($ thousands)		2013		2012		2011
Cash:						
Long-term incentive plans expense	$	23,262	$	5,618	$	14,443
Non-Cash:						
Stock Option Plan expense		9,213		10,297		12,330
Equity swap gain		(5,450)		(412)		–
Share-based compensation expense	$	27,025	$	15,503	$	26,773

(i) Long-Term Incentive Plans

The following table summarizes the PSU, RSU and DSU activity for the year ended December 31, 2013 and other information at December 31, 2013:

For the year ended December 31, 2013 (thousands of units)	PSU	RSU	DSU
Balance, beginning of year	605	963	34
Granted	370	462	78
Vested	(256)	(469)	(13)
Forfeited	(69)	(135)	–
Balance, end of year	650	821	99

At December 31, 2013 (in $thousands, except for years)	PSU	RSU	DSU
Recognized cash share-based compensation expense(1)	$ 14,965	$ 11,271	$ 2,075
Unrecognized cash share-based compensation expense	13,966	6,730	–
Intrinsic value(2)	$ 28,931	$ 18,001	$ 2,075
Weighted-average remaining contractual term (years)(3)	1.6	0.9	–

(1) Recognized amounts are included in accounts payable on the Consolidated Balance Sheets. At December 31, 2013 the plans had a liability balance of $28.3 million.
(2) Includes estimated performance multipliers for the PSU plan. Unrecognized amounts will be recorded to cash share-based compensation expense over the remaining vesting term.
(3) DSU awards vest upon a Director leaving the Board.

For the year ended December 31, 2013 the Company recorded cash share-based compensation costs of $23.3 million (December 31, 2012 – $5.6 million, December 31, 2011 – $14.4 million) and paid $11.1 million on settlements in relation to its long-term incentive plans (December 31, 2012 – $14.0 million, December 31, 2011 – $18.0 million).

(ii) Stock Option Plan

The Company uses the Black-Scholes option pricing model to estimate the fair value of options granted under the Stock Option Plan. The following assumptions were used to arrive at the estimates of fair value during each of the respective reporting periods:

Weighted average for the period	December 31, 2013	December 31, 2012	December 31, 2011
Dividend yield(1)	8.0%	8.2%	7.14%
Volatility(1)	27.80%	28.35%	35.00%
Risk-free interest rate	1.51%	1.35%	2.34%
Forfeiture rate	10.0%	10.0%	9.4%
Expected life	4.5 years	4.5 years	4.5 years

(1) Reflects the expected dividend yield and volatility of Enerplus shares over the expected life of the option.

The following table summarizes the stock option plan activity for the year ended December 31, 2013:

Year ended December 31, 2013	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	10,768	$ 22.11
Granted	6,158	14.11
Exercised	(1,042)	14.25
Forfeited	(2,208)	22.34
Expired	(262)	44.09
Options outstanding, end of year	13,414	$ 18.65
Options exercisable, end of year	4,185	$ 23.09

At December 31, 2013, 4,185,000 options were exercisable at a weighted average reduced exercise price of $23.09 with a weighted average remaining contractual term of 4.07 years, giving an aggregate intrinsic value of $5.2 million (December 31, 2012 – nil, December 31, 2011 – $4.4 million). The total intrinsic value of options exercised during the year ended December 31, 2013 was $2.7 million (December 31, 2012 – $0.3 million, December 31, 2011 – $6.1 million). The weighted average grant date fair value of options granted for the year ended December 31, 2013 was $8.1 million (December 31, 2012 – $13.5 million, December 31, 2011 – $10.3 million).

At December 31, 2013 the total share-based compensation expense related to non-vested options not yet recognized was $4.6 million. The expense is expected to be recognized in net income over a weighted-average period of 1.3 years.

d) Paid-in Capital

The following tables summarize the Paid-in Capital activity for the year and the ending balances as at December 31:

($ thousands)	2013	2012	2011
Balance, beginning of year	$ 32,293	$ 23,115	$ 20,156
Stock Option Plan – exercised	(3,108)	(1,119)	(9,371)
Stock Option Plan – expensed	9,213	10,297	12,330
Balance, end of year	$ 38,398	$ 32,293	$ 23,115

e) Basic and Diluted Earnings Per Share

Net income/(loss) per share has been determined as follows:

(thousands, except per share amounts)	2013	2012	2011
Net income/(loss)	$ 47,976	$ (270,697)	$ 12,811
Weighted average shares outstanding – Basic	200,567	195,633	179,889
Dilutive impact of options(1)	837	–	456
Weighted average shares outstanding – Diluted	201,404	195,633	180,345
Net income/(loss) per share			
Basic	0.24	(1.38)	0.07
Diluted	0.24	(1.38)	0.07

(1) For the year ended December 31, 2012 options are anti-dilutive as their conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2013, the carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value due to the short-term maturity of the instruments.

Enerplus' portfolio of marketable securities consists of publicly traded investments. At December 31, 2013 the fair value of marketable securities was $13.4 million (December 31, 2012 – $7.7 million).

At December 31, 2013 senior notes included in long-term debt had a carrying value of $810.9 million and a fair value of $837.8 million (December 31, 2012 – $808.6 million and $896.9 million, respectively). The fair value of senior notes was estimated by discounting future interest and principle payments using available market information at the balance sheet date.

There were no transfers between fair value hierarchy levels during the period.

b) Derivative Financial Instruments

The deferred financial assets and credits on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following tables summarize the change in fair value for the respective periods:

Gain/(Loss) ($ thousands)	December 31, 2013	December 31, 2012	December 31, 2011	Income Statement Presentation
Interest Rate Swaps	$ 478	$ 1,125	$ 2,037	Interest Expense
Cross Currency Interest Rate Swap:				
Interest	(1,306)	(2,963)	(355)	Interest Expense
Foreign Exchange	19,920	15,118	15,133	Foreign Exchange
Foreign Exchange Swaps	8,110	947	6,257	Foreign Exchange
Electricity Swaps	758	(3,108)	2,756	Operating Expense
Equity Swaps	5,450	412	–	General and Administrative
Commodity Derivative Instruments:				
Oil	(65,504)	70,283	18,733	Commodity derivative instruments
Gas	(2,994)	3,349	(12,641)	
Total Gain/(Loss)	$ (35,088)	$ 85,163	$ 31,920	

The following table summarizes the income statement effects of Enerplus' commodity derivative instruments:

($ thousands)	2013	2012	2011
Change in fair value of commodity derivative instruments gain/(loss)	$ (68,498)	$ 73,632	$ 6,092
Net realized cash gain/(loss)	26,628	18,363	(33,184)
Commodity derivative instruments gain/(loss)	$ (41,870)	$ 91,995	$ (27,092)

The following tables summarize the fair values at the respective period ends:

	December 31, 2013				December 31, 2012			
	Assets		Liabilities		Assets		Liabilities	
($ thousands)	Current	Long-term	Current	Long-term	Current	Long-term	Current	Long-term
Interest Rate Swaps	$ –	$ –	$ –	$ –	$ –	$ –	$ 478	$ –
Cross Currency Interest Rate Swap	–	–	15,548	–	–	–	17,035	17,127
Foreign Exchange Swaps	564	15,135	–	–	–	7,745	156	–
Electricity Swaps	–	–	95	–	–	–	853	–
Equity Swaps	1,723	4,139	–	–	144	268	–	–
Commodity Derivative Instruments:								
Oil	4,138	–	18,970	–	50,672	–	–	–
Gas	2,773	–	2,418	–	3,349	–	–	–
Total	$ 9,198	$ 19,274	$ 37,031	$ –	$ 54,165	$ 8,013	$ 18,522	$ 17,127

c) Risk Management

(i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes net of royalties and production taxes.

The following tables summarize Enerplus' price risk management positions at February 4th, 2014:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl[1]
Jan 1, 2014 – Jan 31, 2014		
WTI Swap	23,000	93.98
WCS Differential Swap	1,000	(23.25)
Feb 1, 2014 – Jun 30, 2014		
WTI Swap	23,000	93.98
WCS Differential Swap	2,000	(21.88)
Jul 1, 2014 – Dec 31, 2014		
WTI Swap	16,000	94.07
WCS Differential Swap	2,000	(21.88)
Jan 1, 2015 – Dec 31, 2015		
WTI Swap	500	90.00

(1) Transactions with a common term have been aggregated and presented as the weighted average price/bbl.

Natural Gas Instruments:

Instrument Type	MMcf/day	CDN$/Mcf	US$/Mcf
Jan 1, 2014 – Dec 31, 2014			
AECO Swap	4.7	3.96	
Apr 1, 2014 – Jun 30, 2014			
AECO Swap	14.2	4.12	
Jul 1, 2014 – Dec 31, 2014			
AECO Swap	28.4	4.25	
Jan 1, 2014 – Dec 31, 2014			
NYMEX Swap	75.0		4.14
NYMEX Purchased Call	25.0		4.17
NYMEX Sold Puts	25.0		3.23
NYMEX Sold Calls	25.0		5.00
Jan 1, 2015 – Dec 31, 2015			
NYMEX Swap	20.0		4.16

Electricity:

Instrument Type	MWh	CDN$/MWh
Jan 1, 2014 – Dec 31, 2014		
AESO Power Swap[1]	16.0	53.33
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap[1]	10.0	51.13

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations and U.S. dollar senior notes and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. Enerplus manages the currency risk relating to its senior notes through the derivative instruments detailed below.

Cross Currency Interest Rate Swap ("CCIRS"):

Concurrent with the issuance of the US$175 million senior notes on June 19, 2002, Enerplus entered into a CCIRS with a syndicate of financial institutions. Under the terms of the swap, the amount of the notes was fixed for purposes of interest and principal payments at a notional amount of CDN$268.3 million. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian bankers' acceptances, plus 1.18%. At December 31, 2013 the remaining USD principal is fixed at a notional amount of CDN$53.7 million. The CCIRS matures on June 2014 in conjunction with the remaining principal repayment on the notes.

Foreign Exchange Swaps:

During 2007 Enerplus entered into foreign exchange swaps on US$54.0 million of notional debt at an average US$/CDN$ exchange rate of 1.02. At December 31, 2013, following the third settlement, Enerplus had US$21.6 million of remaining notional debt swapped. These foreign exchange swaps mature between October 2014 and October 2015 in conjunction with the remaining principal repayments on the US$54.0 million senior notes.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. These foreign exchange swaps mature between June 2017 and June 2021 in conjunction with the principal repayments on the US$225.0 million senior notes.

Interest Rate Risk:

At December 31, 2013, approximately 74% of Enerplus' debt was based on fixed interest rates and 26% was based on floating interest rates. At December 31, 2013, Enerplus did not have any interest rate derivatives outstanding other than the CCIRS mentioned above.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its cash settled long-term incentive plans detailed in Note 13.

Equity Swaps:

Enerplus has entered into various equity swaps maturing between 2014 and 2016 and has effectively fixed the future settlement cost at a weighted average price of $13.86 per share on 1,130,000 shares, representing approximately 77% of the notional shares outstanding under these plans.

(ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

Enerplus mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At December 31, 2013 approximately 71% of Enerplus' marketing receivables were with companies considered investment grade.

At December 31, 2013 approximately $4.5 million or 3% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2013 was $2.8 million (December 31, 2012 – $2.8 million).

(iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, access to capital markets, as well as acquisition and divestment activity.

16) COMMITMENTS, CONTINGENCIES AND GUARANTEES

a) Commitments

Enerplus has the following minimum annual commitments at December 31, 2013:

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2014	2015	2016	2017	2018	Thereafter
Transportation commitments	$ 102,677	$ 30,416	$ 25,486	$ 13,383	$ 11,988	$ 3,525	$ 17,879
Processing commitments	50,593	10,250	9,570	9,054	8,179	6,770	6,770
Drilling and completions	11,582	11,582	–	–	–	–	–
Power infrastructure	13,913	4,020	7,914	1,979	–	–	–
Office leases	73,056	13,611	11,819	12,109	12,348	12,459	10,710
Total commitments(1)(2)	$ 251,821	$ 69,879	$ 54,789	$ 36,525	$ 32,515	$ 22,754	$ 35,359

(1) Crown and surface royalties, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(2) US$ commitments have been converted to CDN$ using the December 31, 2013 foreign exchange rate of 1.0636.

Transportation for Enerplus' Bakken crude oil in the U.S. has been contracted for 8,500 bbl/day up until April 2016 with 7,500 bbl/day of that continuing through December 2017.

Enerplus has contracted up to 191 MMcf/day of natural gas pipeline capacity with contract terms ranging from one month to 5 years.

Enerplus has office lease commitments for both its Canadian and U.S. operations that expire in 2019. The annual costs of these lease commitments include rent and operating fees.

b) Contingencies

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

c) Guarantees

(i) Corporate indemnities have been provided by Enerplus to all directors and officers for various items including costs to settle suits or actions due to their association with Enerplus. Enerplus has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. Each indemnity, subject to certain exceptions, applies for so long as the indemnified person is a director or officer of Enerplus.

(ii) Enerplus may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents Enerplus from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

17) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2013 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales	$ 676,502	$ 675,970	$ 1,352,472
Plant, property and equipment	1,081,259	1,360,095	2,441,354
Goodwill	451,121	158,854	609,975

As at and for the year ended December 31, 2012 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales	$ 707,985	$ 445,349	$ 1,153,334
Plant, property and equipment	1,323,850	1,013,945	2,337,795
Goodwill	451,121	148,595	599,716

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2013	December 31, 2012	December 31, 2011
Accounts receivable	$ (6,935)	$ (34,384)	$ (4,333)
Other current assets	(1,156)	4,007	38,223
Accounts payable	36,942	(58,552)	37,597
	$ 28,851	$ (88,929)	$ 71,487

b) Other

($ thousands)	December 31, 2013	December 31, 2012	December 31, 2011
Income taxes paid	$ 4,448	$ 17,946	$ 49,592
Interest paid	$ 55,957	$ 49,826	$ 47,756

EXHIBIT 99.3

MD&A

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 20, 2014 and is to be read in conjunction with the audited consolidated financial statements prepared in accordance with United States Generally Accepted Accounting Principles (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011.

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information.

ADOPTION OF UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

We have converted our financial reporting from International Financial Reporting Standards ("IFRS") to United States Generally Accepted Accounting Principles ("U.S. GAAP") pursuant to U.S. securities regulations as (i) over 50% of the book value of our assets (as previously calculated under IFRS) was in the United States, and (ii) over 50% of our common shares are held by U.S. residents. Reporting under U.S. GAAP began with our financial statements for the year ended December 31, 2013 with comparatives for 2012 and 2011. These U.S. GAAP financial statements are presented in Canadian dollars and satisfy both our Canadian and U.S. securities filing obligations, and IFRS based statements will no longer be prepared.

We continue to qualify as a foreign private issuer for our U.S. securities filings as less than 50% of the book value of our assets is in the United States, as calculated under U.S. GAAP, as at June 30, 2013. We are required to reassess this annually at the end of our second quarter and should our U.S. asset book value exceed 50% of our corporate total as calculated under U.S. GAAP, we would fail to qualify as a foreign private issuer and would become subject to U.S. domestic filing requirements effective the first day of the following calendar year.

The most significant differences between U.S. GAAP and IFRS that impact Enerplus relate to the accounting for our oil and gas assets, particularly accounting for impairment, depletion, divestments, and asset retirement obligations.

Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under IFRS and Canadian industry protocol oil and gas sales and production volumes are presented before deduction of any royalties. In order to continue to be comparable with our Canadian peer companies, this MD&A presents our production and BOE measures on a Company interest basis before deduction of any royalties.

The following provides a reconciliation of our production volumes:

Average Daily Production Volumes	Year ended December 31 2013	2012	2011
Company interest production volumes			
Crude oil (bbls/day)	38,250	36,509	30,181
Natural gas liquids (bbls/day)	3,472	3,627	3,306
Natural gas (Mcf/day)	288,423	251,773	251,068
Company interest production volumes (BOE/day)	89,793	82,098	75,332
Royalty volumes			
Crude oil (bbls/day)	6,938	6,315	4,923
Natural gas liquids (bbls/day)	802	837	770
Natural gas (Mcf/day)	42,192	30,294	31,015
Royalty volumes (BOE/day)	14,772	12,201	10,862
Net production volumes			
Crude oil (bbls/day)	31,312	30,194	25,258
Natural gas liquids (bbls/day)	2,670	2,790	2,536
Natural gas (Mcf/day)	246,231	221,479	220,053
Net production volumes (BOE/day)	75,021	69,897	64,470

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

"Netback" is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and natural gas sales revenue (net of transportation), less royalties, production taxes and operating costs.

"Funds Flow" is used to analyze operating performance, leverage and liquidity. Funds flow is calculated as net cash provided by operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures.

Reconciliation of Cash Flow from Operating Activities to Funds flow	Year ended December 31 2013	2012	2011
Cash flow from operating activities	$ 766.5	$ 535.7	$ 624.2
Asset retirement obligation expenditures	16.6	19.9	21.7
Changes in non-cash operating working capital	(28.9)	88.9	(71.5)
Funds flow	$ 754.2	$ 644.5	$ 574.4

"Debt to Funds Flow Ratio" is used to analyze leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash, divided by a trailing 12 months of funds flow.

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as dividends to shareholders, net of our Stock Dividend Program ("SDP") and former Dividend Reinvestment Program ("DRIP") proceeds, plus capital spending (including office capital) divided by funds flow.

2013 FOURTH QUARTER OVERVIEW

Production continued to exceed our expectations averaging 94,167 BOE/day during the fourth quarter, concluding a year of significant production growth. Strong fourth quarter production was driven by continued outperformance and the acquisition of additional working interests in the Marcellus. Despite an improvement in natural gas prices, funds flow during the fourth quarter totaled $180.7 million compared to $196.2 million in the third quarter, primarily due to wider crude oil differentials along with higher share-based compensation. We continued to focus our portfolio during the quarter, recognizing proceeds of $168.7 million through our divestment activity. We maintained a strong balance sheet exiting the year with a conservative trailing 12-month debt to funds flow ratio of 1.4x.

SUMMARY FOURTH QUARTER INFORMATION

In comparing the fourth quarter of 2013 with the same period in 2012:

- Average daily production was 94,167 BOE/day compared to 85,490 BOE/day in 2012, with the majority of the growth coming from our Marcellus and Fort Berthold properties in the U.S. and our Wilrich properties in Canada. Our average daily production for December was 99,569 BOE/day, ahead of our exit guidance of 95,000 BOE/day.
- Funds flow totaled $180.7 million compared to $200.4 million in 2012. Funds flow decreased from the fourth quarter of 2012 primarily due to higher operating costs and share-based compensation, offset by higher oil and gas sales.
- Cash general and administrative ("G&A") expenses were $2.28/BOE compared to $2.34/BOE in 2012. The decrease in cash G&A expense on a per BOE basis was due to higher production during the period.
- Cash share-based compensation expense increased to $1.06/BOE compared to $0.03/BOE in 2012 due to the increase in our share price during the quarter.
- Capital spending increased to $223.0 million compared to $160.9 million in 2012. Our fourth quarter capital spending was in line with expectations with the majority of our spending focused on our core operating areas. During the quarter, we invested $95.9 million in Fort Berthold, $24.3 million in the Marcellus, $48.5 million on our Canadian crude oil waterflood properties, and $43.2 million on our Canadian Deep Gas properties.
- Property and land acquisitions were $173.4 million compared to $121.4 million in 2012. During the fourth quarter of 2013 we purchased additional working interests in our core Marcellus properties for $157.9 million, representing approximately 42 MMcf/day of production.
- Divestments totaled $168.0 million compared to $220.1 million in 2012. In the fourth quarter we disposed of non-core Canadian oil properties for proceeds of $103.6 million and entered into agreements to sell our undeveloped Montney acreage for $134.6 million, after adjustments, of which $65.7 million was closed during the quarter with the remainder recognized in January 2014. During the fourth quarter of 2012 we divested of our non-core properties in Manitoba for proceeds of $218.1 million.

SELECTED FOURTH QUARTER CANADIAN AND U.S. FINANCIAL RESULTS

(CDN$ millions, except per unit amounts)	Three months ended December 31, 2013 Canada	U.S.	Total	Three months ended December 31, 2012 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,703	21,028	37,731	20,713	17,884	38,597
Natural gas liquids (bbls/day)	2,858	955	3,813	3,177	399	3,576
Natural gas (Mcf/day)	165,114	150,625	315,739	188,628	71,276	259,904
Total average daily production (BOE/day)	47,080	47,087	94,167	55,328	30,162	85,490
Pricing[2]						
Crude oil (per bbl)	$ 70.05	$ 83.89	$ 77.77	$ 72.01	$ 82.25	$ 76.75
Natural gas liquids (per bbl)	52.39	59.87	54.26	48.09	41.08	47.31
Natural gas (per Mcf)	3.12	3.41	3.26	2.76	3.67	3.01
Capital Expenditures						
Capital spending	$ 102.1	$ 120.9	$ 223.0	$ 50.3	$ 110.6	$ 160.9
Acquisitions	0.4	173.0	173.4	(0.2)	121.6	121.4
Dispositions	(168.7)	0.7	(168.0)	(220.2)	–	(220.2)
Revenues						
Oil and natural gas sales[2]	$ 168.8	$ 210.6	$ 379.4	$ 199.8	$ 160.9	$ 360.7
Commodity derivative instruments gain/(loss)	10.2	–	10.2	17.7	–	17.7
Expenses						
Operating	$ 66.8	$ 24.4	$ 91.2	$ 57.9	$ 13.9	$ 71.8
Royalties	23.7	40.9	64.6	26.7	30.5	57.2
Production taxes	2.3	15.6	17.9	2.4	15.4	17.8
General and administrative	14.5	5.2	19.7	20.0	3.9	23.9
Depletion, depreciation, amortization and accretion	59.3	63.8	123.1	87.1	55.4	142.5
Current income tax expense/(recovery)	(0.4)	0.3	(0.1)	(2.2)	1.5	(0.7)

(1) Company interest volumes, before royalties.
(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

2013 OVERVIEW

Summary of Guidance and Results	Original 2013 Guidance	Revised 2013 Guidance	2013 Results	2014 Guidance
Average annual production (BOE/day)	82,000 – 85,000	89,000	89,793	96,000 – 100,000
Capital spending (CDN$ millions)	$ 685	$ 685	$ 681	$ 760
Production mix volumes (% crude oil and liquids)	50%	48%	46%	48%
Average royalty and production tax rate (% of gross sales, net of transportation)	21%	21%	21%	23.5%
Operating costs (per/BOE)	$ 10.70	$ 10.70	$ 10.48	$ 10.25
G&A Expenses – cash (per/BOE)	$ 2.70	$ 2.70	$ 2.54	$ 2.45
Share based compensation expenses – cash (per/BOE)	$ 0.45	$ 0.60	$ 0.71	$ 0.25

Production increased by over 9% during 2013, averaging 89,793 BOE/day and exceeding our annual average guidance of 89,000 BOE/day. We exited the year with average production of 99,569 BOE/day in December, exceeding our exit guidance of 95,000 BOE/day. We had an average crude oil and liquids weighting of 46% for 2013 compared to 49% in 2012 despite growth in our crude oil production of 5% year-over-year. Our crude oil divestment activity and production outperformance in the Marcellus contributed to the change in our production weighting.

Capital spending and operating costs were lower than expected at $681.4 million and $10.48/BOE respectively. G&A expenses were consistent with our expectations at $2.54/BOE, however cash share-based compensation expense was higher than expected at $0.71/BOE given the increase in our share price during the period. Funds flow increased 17% over 2012 at $754.2 million. Stronger crude oil and natural gas prices and higher production contributed to this increase.

We continued to make progress in focusing our portfolio and concentrating on our core operating areas. We sold $365.1 million of non-core assets representing production of approximately 2,700 BOE/day and reinvested $244.8 million into our core areas through transactions that included the acquisition of crude oil waterflood properties in Canada and additional working interests in the Marcellus. On a net basis, we realized proceeds of $120.3 million from our acquisition and divestment activities during the period.

With the increase in funds flow and a reduction in capital spending, our adjusted payout ratio fell to 114% in 2013. Monthly dividends to shareholders were maintained throughout the year totaling $1.08 per share. Our financial flexibility also improved in 2013, as we ended the year with a debt to funds flow ratio of 1.4x and approximately $786 million of available credit on our bank facility.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2013	2012	2011
Crude oil (bbls/day)	38,250	36,509	30,181
Natural gas liquids (bbls/day)	3,472	3,627	3,306
Natural gas (Mcf/day)	288,423	251,773	251,068
Total daily sales (BOE/day)	89,793	82,098	75,332

2013 versus 2012

Production for 2013 averaged 89,793 BOE/day, representing an increase of over 9% from 2012. Our crude oil production increased 5% as production from our Fort Berthold properties grew by approximately 4,700 BOE/day in 2013. Our natural gas production increased 15% primarily due to growth in the Marcellus where we more than doubled our production volumes from the prior year. Somewhat offsetting the production growth were 2,700 BOE/day of non-core asset divestments throughout 2013 as well as production declines in our Canadian conventional natural gas properties due to limited capital investment in the assets.

2012 versus 2011

Production for 2012 averaged 82,098 BOE/day, representing an increase of 9% from 2011. Our crude oil production increased by 21% mainly due to our successful capital development program at our Fort Berthold properties. Natural gas volumes were relatively flat year-over-year as increased volumes from our Marcellus assets offset production declines on our Canadian conventional natural gas properties.

2014 Guidance

We expect to deliver 9% production growth again in 2014, targeting annual average production between 96,000 BOE/day and 100,000 BOE/day. This guidance does not contemplate future acquisitions or divestments.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following tables summarize our average selling prices, benchmark prices and differentials.

Average Selling Price[(1)]	2013	2012	2011
Crude oil (per bbl)	$ 83.99	$ 78.19	$ 83.48
Natural gas liquids (per bbl)	52.25	53.01	64.99
Natural gas (per Mcf)	3.26	2.39	3.72
Per BOE	48.11	44.56	48.85

(1) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

Average Benchmark Pricing	2013	2012	2011
WTI crude oil (US$/bbl)	$ 97.97	$ 94.21	$ 95.12
AECO natural gas – monthly index (CDN$/Mcf)	3.16	2.40	3.68
AECO natural gas – daily index (CDN$/Mcf)	3.17	2.39	3.62
NYMEX natural gas – monthly NX3 index (US$/Mcf)	3.67	2.80	4.07
US/CDN exchange rate	1.03	1.00	0.99

Average Differentials (US$/bbl or US$/Mcf)	**2013**	**2012**	**2011**
MSW Edmonton – WTI	$ (7.57)	$ (7.79)	$ 1.33
WCS Hardisty – WTI	(25.20)	(21.03)	(17.15)
Brent Futures (ICE) – WTI	10.77	17.45	15.72
AECO monthly – NYMEX	(0.58)	(0.39)	(0.32)

CRUDE OIL AND NATURAL GAS LIQUIDS

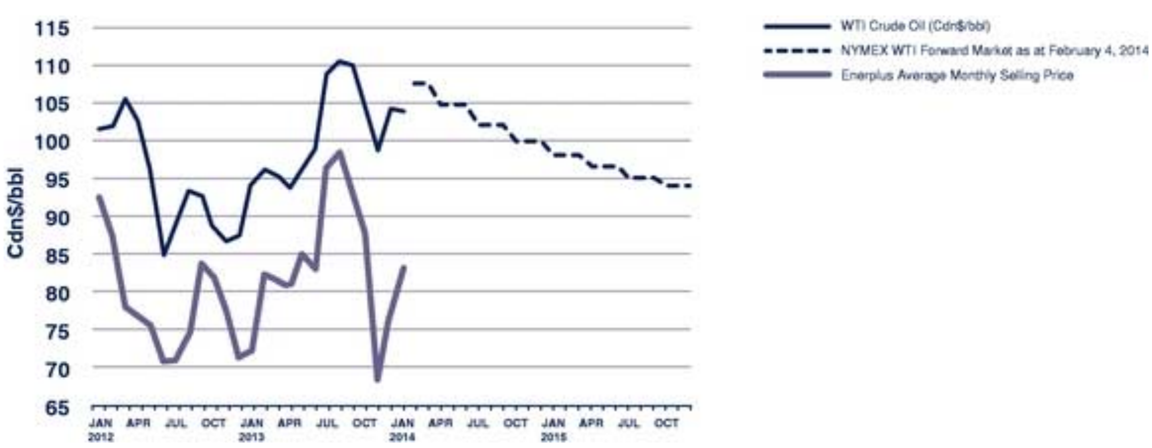
WTI started 2013 trading at US$93.12/bbl and ended the year trading at US$98.42, averaging US$97.97/bbl over the period. A low of US$86.68/bbl was reached in April as U.S. crude oil inventories reached their highest point in 25 years. Geopolitical tensions in Syria, Iran and Libya, combined with a strong turnaround in U.S. refining demand and associated decline in U.S. crude oil stocks, helped push WTI prices to a peak of US$110.53/bbl in early September. Some of the geopolitical tension eased during the latter part of the year, resulting in WTI prices falling by over US$17.00/bbl by the end of the year. Brent/WTI differentials averaged US$10.77/bbl, which was US$6.68/bbl narrower versus 2012, as increased domestic light sweet crude oil production began to displace imported crudes.

Heavy crude oil differentials in Canada continued to widen in 2013, averaging US$4.17/bbl wider than 2012, due to increased Canadian heavy crude oil production and a number of unplanned outages and refinery turnarounds throughout the year. Light oil differentials in Canada were virtually unchanged on average compared to 2012, although they widened significantly in the fourth quarter due to constraints on export pipelines and the continued growth in light oil production in the U.S.

Enerplus' crude oil stream differential discount to WTI in 2013 averaged US$13.98/bbl versus US$16.02/bbl in 2012. The average price received for our crude oil (net of transportation costs) was $83.99/bbl for 2013, a 7% increase over 2012. In comparison, the WTI benchmark increased by 4% over the same period. The difference between the change in WTI and the change in our realized prices is largely due to a weaker Canadian dollar in 2013 which helped to increase our realized prices.

In 2014 we expect our U.S. Bakken and Three Forks oil will trade at US$12.00/bbl discount to WTI. In Canada, we expect the Mixed Sweet Blend ("MSW") to trade at an US$8.00/bbl discount and Western Canadian Select ("WCS") to trade at a US$25.00/bbl discount to WTI during 2014.

MONTHLY CRUDE OIL PRICES



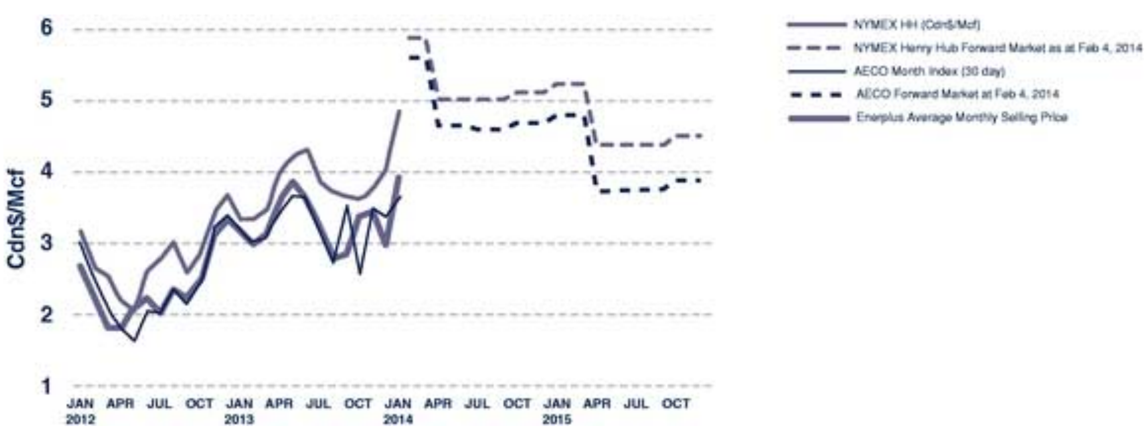
NATURAL GAS

Natural gas prices at both AECO and NYMEX strengthened considerably versus 2012. AECO monthly index prices increased by 32% to average $3.16/Mcf for the year, while NYMEX gas prices increased by 31% to average US$3.67/Mcf. Colder than normal weather late last winter pushed AECO monthly prices to $3.68/Mcf in the spring, with NYMEX reaching US$4.19/Mcf in June. These gains were short-lived as significant production growth in the U.S. and cooler than expected weather put significant pressure on natural gas prices during the summer months. However, record withdrawals from storage were seen in December in the U.S., helping push spot NYMEX prices to approximately US$4.50/Mcf before year-end.

Natural gas prices in the Marcellus weakened throughout the year given increased production in the region and takeaway capacity constraints. Monthly spot prices on the Transco Leidy and Tennessee Gas Pipeline 300 Leg weakened from approximately $0.30/MMBtu below NYMEX in early summer to as high as $2.00/MMBtu below NYMEX by the fourth quarter due to increased capacity constraints. In 2013 approximately 50% of our natural gas was sold under long-term sales contracts at market points with stronger pricing. This provided some protection from these discounts, resulting in our realized discount to NYMEX averaging US$0.33/MMBtu for the year. We expect wider differentials to continue in the region until pipeline expansions are built, and within the context of stronger natural gas prices we are forecasting our differential to NYMEX to average $1.00/MMBtu in 2014.

Overall, we sold our natural gas for an average price of $3.26/Mcf (net of transportation costs) in 2013 which represented a 36% increase from 2012. The increase in our realized price was in line with the year-over-year changes in both AECO and NYMEX prices.

MONTHLY NATURAL GAS PRICES



Price Risk Management

We have a price risk management program that considers our overall financial position, the economics of our capital program and potential acquisitions. We have hedged a significant portion of our crude oil production in 2014 as it currently accounts for approximately 80% of our corporate netback. As of February 4, 2014 we have swapped an average of 19,500 bbls/day for 2014 at an average price of US$94.02/bbl, which represents approximately 59% of our forecasted net oil production after royalties. We have not added material crude oil positions for 2015 given the significant backwardation in the forward curve.

We have entered into WCS differential swap positions for 2014 to manage exposure against heavy crude oil differentials. These differential swaps have been fixed at WTI less US$21.88/bbl on 2,000 bbls/day for February through December of 2014.

As of February 4, 2014 we have downside protection on approximately 40% of our forecasted natural gas production after royalties for 2014. This is comprised of 75,000 Mcf/day at a NYMEX price of US$4.14/Mcf. In addition, we purchased a call spread whereby we participate in price upside between US$4.17/Mcf and US$5.00/Mcf on 25,000 Mcf/day at NYMEX. At AECO we have approximately 19,000 Mcf/day hedged at an average price of CDN$4.21/Mcf, weighted towards the second half of 2014. For 2015, we have swapped 20,000 Mcf/day at a NYMEX price of US$4.16/Mcf.

The following is a summary of our financial contracts in place at February 4, 2014, expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)[1]			AECO Natural Gas (CDN$/Mcf)			NYMEX Natural Gas (US$/Mcf)	
	Jan 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Dec 31, 2015	Jan 1, 2014 – Mar 31, 2014	Apr 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Jan 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Dec 31, 2015
Sold Puts							$ 3.23	
%							11%	
Swaps	$ 93.98	$ 94.07	$ 90.00	$ 3.96	$ 4.12	$ 4.25	$ 4.14	$ 4.16
%	70%	48%	2%	2%	6%	12%	32%	9%
Sold Calls							$ 5.00	
%							11%	
Purchased Calls							$ 4.17	
%							11%	

(1) Based on weighted average price (before premiums), assumed average annual production of 98,000 BOE/day for 2014 and 2015, less royalties and production taxes of 23.5% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Risk Management Gains/(Losses) ($ millions)	2013	2012	2011
Cash gains/(losses):			
Crude oil	$ 24.4	$ 18.4	$ (46.5)
Natural gas	2.2	–	13.3
Total cash gains/(losses)	$ 26.6	$ 18.4	$ (33.2)
Non-cash gains/(losses) on financial contracts:			
Change in fair value – crude oil	$ (65.5)	$ 70.3	$ 18.7
Change in fair value – natural gas	(3.0)	3.3	(12.6)
Total non-cash gains/(losses)	$ (68.5)	$ 73.6	$ 6.1
Total gains/(losses)	$ (41.9)	$ 92.0	$ (27.1)

(Per BOE)	2013	2012	2011
Total cash gains/(losses)	$ 0.81	$ 0.61	$ (1.21)
Total non-cash gains/(losses)	(2.09)	2.45	0.22
Total gains/(losses)	$ (1.28)	$ 3.06	$ (0.99)

2013 versus 2012

During 2013 we realized cash gains of $24.4 million on our crude oil contracts and $2.2 million on our natural gas contracts. In comparison, during 2012 we realized cash gains of $18.4 million on our crude oil contracts. The cash gains in 2013 and 2012 were due to contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At December 31, 2013 the fair value of our crude oil contracts represented a loss position of $14.8 million, while our natural gas contracts represented a gain position of $0.3 million. For the year ended December 31, 2013 the fair value of our crude oil contracts decreased $65.5 million while the fair value of our natural gas contracts decreased $3.0 million. See Note 15 for details.

2012 versus 2011

During 2012 we realized cash gains of $18.4 million on our crude oil contracts. In comparison, in 2011 we realized cash losses of $46.5 million on our crude oil contracts and gains of $13.3 million on our natural gas contracts. The cash gains in 2012 were due to contracts which provided floor protection above market prices. The cash losses in 2011 were a result of crude oil prices rising above our fixed price swap positions.

At December 31, 2012 the fair value of our crude oil and natural gas contracts represented gains of $50.7 million and $3.3 million respectively. For the year ended December 31, 2012 the fair value of our crude oil and natural gas contracts increased $70.3 million and $3.3 million, respectively.

Revenues

($ millions)		2013		2012		2011
Oil and natural gas sales	$	1,616.8	$	1,365.5	$	1,363.7
Royalties		(264.3)		(212.2)		(205.1)
Oil and natural gas sales, net of royalties	$	1,352.5	$	1,153.3	$	1,158.6

2013 versus 2012

Oil and gas sales revenues in 2013 increased to $1,616.8 million compared to $1,365.5 million in 2012, due to higher realized prices and increased production for both crude oil and natural gas.

2012 versus 2011

Oil and gas sales revenues of $1,365.5 million in 2012 were similar to 2011 revenues of $1,363.7 million. Increased production volumes in 2012 were offset by lower realized prices.

Royalties and Production Taxes

($ millions, except per BOE amounts)		2013		2012		2011
Royalties	$	264.3	$	212.2	$	205.1
Per BOE	$	8.06	$	7.06	$	7.46
Production taxes	$	70.4	$	56.6	$	40.1
Per BOE	$	2.15	$	1.89	$	1.46
Royalties and production taxes	$	334.7	$	268.8	$	245.2
Per BOE	$	10.21	$	8.95	$	8.92
Royalties and production taxes (% of oil and natural gas sales, net of transportation)		21%		20%		18%

(1) Prior to adoption of U.S. GAAP, Enerplus reported the aggregate of royalties and production taxes as a single "Royalties" category on the Consolidated Income Statement.

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges.

2013 versus 2012

Royalties and production taxes increased to $334.7 million in 2013 from $268.8 million in 2012 due to increased production, particularly in the U.S. where rates are higher. Royalties and production taxes averaged 21% of oil and gas sales (net of transportation) in 2013 compared to 20% in 2012.

2012 versus 2011

Royalties and production taxes were $268.8 million in 2012 compared to $245.2 in 2011. Royalties and production taxes increased to 20% of oil and gas sales (net of transportation) from 18% in 2011, due to increased U.S. production levels.

Guidance

We are expecting average royalty and production taxes in 2014 to increase to 23.5% of expected oil and gas sales (net of transportation).

Transportation Costs

($ millions, except per BOE amounts)	2013	2012	2011
Transportation costs	$ 39.9	$ 26.6	$ 20.6
Per BOE	$ 1.22	$ 0.88	$ 0.75

Transportation costs for 2013 were $39.9 million compared to $26.6 million in 2012 and $20.6 million in 2011. The increased transportation costs are related to our increasing U.S. production as well as costs associated with securing U.S. pipeline capacity.

Operating Expenses

($ millions, except per BOE amounts)	2013	2012	2011
Operating Expenses	$ 343.4	$ 319.0	$ 280.4
Per BOE	$ 10.48	$ 10.62	$ 10.20

2013 versus 2012

Our 2013 operating expenses were in line with expectations at $343.4 million ($10.48/BOE) compared to $319.0 million ($10.62/BOE) in 2012. Operating costs improved on a per BOE basis due to increased production from our lower cost properties along with the divestment of non-core properties that had higher operating costs.

2012 versus 2011

Our 2012 operating expenses totaled $319.0 million ($10.62/BOE) compared to $280.4 million ($10.20/BOE) in 2011. In 2012 we had additional facility charges at Fort Berthold and higher well servicing and repairs and maintenance costs as poor weather in 2011 delayed some maintenance into 2012.

2014 Guidance

We are expecting our 2014 operating expenses to decrease to approximately $10.25/BOE.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Year ended December 31, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	42,587 BOE/day	283,237 Mcfe/day	89,793 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 76.90	$ 3.70	$ 48.11
Royalties and production taxes	(18.39)	(0.48)	(10.21)
Cash operating costs	(12.23)	(1.49)	(10.50)
Netback before hedging	$ 46.28	$ 1.73	$ 27.40
Cash gains/(losses)	1.57	0.02	0.81
Netback after hedging	$ 47.85	$ 1.75	$ 28.21
Netback before hedging ($ millions)	$ 719.3	$ 178.7	$ 898.0
Netback after hedging ($ millions)	$ 743.7	$ 180.9	$ 924.6

	Year ended December 31, 2012		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	40,136 BOE/day	251,773 Mcfe/day	82,098 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 72.05	$ 3.04	$ 44.56
Royalties and production taxes	(16.06)	(0.36)	(8.95)
Cash operating costs	(11.94)	(1.52)	(10.51)
Netback before hedging	$ 44.05	$ 1.16	$ 25.10
Cash gains/(losses)	1.25	–	0.61
Netback after hedging	$ 45.30	$ 1.16	$ 25.71
Netback before hedging ($ millions)	$ 647.2	$ 107.1	$ 754.3
Netback after hedging ($ millions)	$ 665.6	$ 107.1	$ 772.7

	Year ended December 31, 2011		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	33,185 BOE/day	252,883 Mcfe/day	75,332 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 77.17	$ 4.42	$ 48.85
Royalties and production taxes	(16.27)	(0.52)	(8.92)
Cash operating costs	(11.77)	(1.52)	(10.30)
Netback before hedging	$ 49.13	$ 2.38	$ 29.63
Cash gains/(losses)	(3.84)	0.14	(1.21)
Netback after hedging	$ 45.29	$ 2.52	$ 28.42
Netback before hedging ($ millions)	$ 595.3	$ 219.4	$ 814.7
Netback after hedging ($ millions)	$ 548.8	$ 232.7	$ 781.5

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of transportation costs.

Our crude oil properties accounted for 80% of our corporate netback before hedging in 2013 compared to 86% and 73% in 2012 and 2011, respectively.

During 2013 crude oil netbacks per BOE and natural gas netbacks per Mcfe increased compared to 2012 primarily due to improved realized prices. Our 2012 crude oil netbacks per BOE after hedging were similar to 2011 as lower realized prices were offset by cash hedging gains, while natural gas netbacks per Mcfe decreased due to lower realized prices.

General and Administrative (G&A) Expenses

Total G&A expenses include cash G&A expenses as well as share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 14 for further details). SBC charges are dependent on our share price and can fluctuate from period to period.

($ millions)	2013	2012	2011
Cash:			
G&A expense[1]	$ 83.2	$ 78.3	$ 67.6
SBC	23.3	5.6	14.5
Non-Cash:			
SBC – equity swap loss/(gain)	(5.4)	(0.4)	–
SBC – Stock option plan	9.2	10.3	12.3
Total G&A expenses	$ 110.3	$ 93.8	$ 94.4

(Per BOE)	2013	2012	2011
Cash:			
G&A expense[1]	$ 2.54	$ 2.61	$ 2.46
SBC	0.71	0.18	0.53
Non-Cash:			
SBC – equity swap loss/(gain)	(0.17)	(0.01)	–
SBC – Stock option plan	0.28	0.34	0.45
Total G&A expenses	$ 3.36	$ 3.12	$ 3.44

(1) Excluding share-based compensation.

2013 versus 2012

Cash G&A expenses were $83.2 million compared to $78.3 million in 2012. The increase in 2013 was primarily related to compensation costs and one-time charges recorded in the first quarter. On a per BOE basis costs decreased 3%.

Cash SBC was $23.3 million in 2013 compared to $5.6 million in 2012. Higher cash SBC in 2013 was the result of our 58% total return in 2013 (share price increase plus dividends) which increased the value of our LTI plans. A portion of our LTI plans have a performance based multiplier that also increased this expense during 2013 because of our total return relative to the TSX oil and gas index.

We recorded non-cash gains of $5.4 million in 2013 compared to gains of $0.4 million in 2012 on our equity swaps. These gains result from the change in fair value of the equity swaps which effectively fix the future settlement cost on a portion of the outstanding units under the plans. At December 31, 2013 we had fixed the settlement cost on 1,130,000 shares at a weighted average price of $13.86 per share.

2012 versus 2011

Cash G&A expenses were $78.3 million in 2012 compared to $67.6 million in 2011. The increase in 2012 was primarily due to expanding our U.S. operations as well as higher professional and legal fees.

Cash SBC expenses decreased to $5.6 million in 2012 from $14.5 million in 2011. Our LTI costs were significantly lower in 2012 as a result of the decrease in our share price during the year.

2014 Guidance

For 2014 we expect cash G&A expenses of approximately $2.45/BOE. We also anticipate cash SBC to decrease to approximately $0.25/BOE as we expect future grants under our LTI plans will be treasury settled as compared to our current practice of cash settlement.

Interest Expense

($ millions)	2013	2012	2011
Interest on senior notes and bank facility	$ 56.7	$ 53.1	$ 47.0
Non-cash interest expense	1.6	1.8	(2.1)
Total interest expense	$ 58.3	$ 54.9	$ 44.9

Interest on our senior notes and bank credit facility in 2013 totaled $58.3 million compared to $54.9 million in 2012 and $44.9 million in 2011. The increases in 2013 and 2012 are due to an increased weighting of senior notes with higher interest rates after our $405 million private placement of senior notes in May 2012. Non-cash amounts recorded in finance expense include unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap ("CCIRS"). See Note 11 for further details.

At December 31, 2013, after including our underlying derivatives, approximately 74% of our debt was based on fixed interest rates and 26% on floating interest rates.

Foreign Exchange

($ millions)	2013	2012	2011
Realized loss/(gain)	$ 17.6	$ 6.5	$ 18.4
Unrealized loss/(gain)	(8.3)	(23.7)	(14.2)
Total foreign exchange loss/(gain)	$ 9.3	$ (17.2)	$ 4.2

We recorded a net foreign exchange loss of $9.3 million in 2013 compared to a gain of $17.2 million in 2012 and loss of $4.2 million in 2011. In each of these years our realized foreign exchange loss includes the second quarter CCIRS settlement on our US$175 million senior notes. Each year, upon settlement of the swap, we realized a foreign exchange loss (2013 – $17.8 million, 2012 – $18.4 million, 2011 – $19.1 million) and recognized a corresponding unrealized gain to remove the mark-to-market position previously recorded on the balance sheet. We also had unrealized foreign exchange gains in 2013 on the translation of our U.S. debt and working capital. See Note 12 for details.

Capital Investment

($ millions)	2013	2012	2011
Capital spending	$ 681.4	$ 853.4	$ 866.5
Office capital	6.5	11.9	11.3
Sub-total	$ 687.9	$ 865.3	$ 877.8
Property and land acquisitions	$ 244.8	$ 185.3	$ 255.2
Property divestments	(365.1)	(275.8)	(641.2)
Sub-total	$ (120.3)	$ (90.5)	$ (386.0)
Total net capital investment	$ 567.6	$ 774.8	$ 491.8

2013

Capital spending in 2013 totaled $681.4 million and was focused primarily on our core development areas with 66% targeting oil development. Throughout the year we spent $314.9 million on our Fort Berthold crude oil properties, $172.9 million on our Canadian crude oil properties, $89.3 million on our liquids rich deep gas properties in Canada and $78.7 million developing our Marcellus assets. Through our capital program in 2013 we added 78 MMBOE of proved plus probable reserves, replacing approximately 238% of our 2013 production.

Property and land acquisitions in 2013 totaled $244.8 million. The most significant transactions included the additional working interests we acquired in our core Marcellus properties for $157.9 million along with $34.4 million for additional working interests in our Pouce Coupe waterflood property in Canada.

Property divestments in 2013 totaled $365.1 million. In Canada we generated proceeds of $257.5 million from the divestment of non-core assets with production of approximately 2,700 BOE/day. We also sold our undeveloped Montney acreage for proceeds of $134.6 million, of which $65.7 million was recognized in 2013 with the remainder recognized in January 2014. In the U.S. we sold facilities in Fort Berthold for proceeds of $35.2 million and entered into fee based processing and gathering contracts.

2012

Capital spending in 2012 totaled $853.4 million with approximately 80% directed towards oil and liquids rich natural gas properties. We spent $441.6 million on our Fort Berthold crude oil property, $168.5 million on our Canadian crude oil properties and $69.5 million on our liquids rich deep gas properties in Canada. We also spent $153.6 million on our Marcellus assets primarily focused on drilling for lease retention in core areas. Through our capital program in 2012 we added 57.3 MMBOE of proved plus probable reserves, replacing approximately 190% of our 2012 production.

Property and land acquisitions for 2012 totaled $185.3 million, the majority of which related to our December acquisition of additional working interests in our operated Sleeping Giant crude oil leases in Montana for $117.6 million. We also spent $37.0 million on our Marcellus carry obligation which fully satisfied our carry commitment.

Property divestments in 2012 were $275.8 million which included the sale of our Manitoba assets for proceeds of $218.1 million and non-core assets in the U.S. for proceeds of $21.9 million.

2011

Capital spending during 2011 totaled $866.5 million and was focused on our key growth areas. We spent $375.0 million on our Bakken oil assets in the U.S. and Canada, $164.0 million on our crude oil waterflood properties, $210.0 million on our Marcellus assets and $84.0 million on our deep gas plays.

Property and land acquisitions in 2011 totaled $255.2 million which included $112.5 million on undeveloped land in Canada and US$111.0 million on our Marcellus carry obligation.

Property divestments in 2011 were $641.2 million including the sale of approximately 91,000 net acres of our Marcellus interests for proceeds of $567.9 million and the divestment of non-core Canadian assets for proceeds of approximately $61.8 million.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

($ millions, except per BOE amounts)	2013	2012	2011
DDA&A expense	$ 593.2	$ 560.3	$ 509.6
Per BOE	$ 18.10	$ 18.65	$ 18.53

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For 2013 DDA&A was $593.2 million compared to $560.3 million in 2012 and $509.6 million in 2011. The increases were primarily due to higher production and capital costs with respect to our U.S. operations.

Impairments

($ millions, except per BOE amounts)	2013	2012	2011
Impairment expense	$ –	$ 781.1	$ 209.4
Per BOE	$ –	$ 26.00	$ 7.62

Under U.S. GAAP, the ceiling test is performed using estimated after-tax future net cash flows from proved reserves as calculated under SEC constant prices using trailing 12-month average commodity prices and discounted at 10 percent ("Standardized Measure"). The Standardized

Measure is not related to Enerplus' capital spending investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Under U.S. GAAP impairments are not reversed in future periods.

Enerplus did not record any ceiling test impairments on its oil and gas properties in 2013. During 2012 and 2011, non-cash impairments totaling $781.1 million and $209.4 million, respectively, were recorded in the United States cost center. These impairments were due to our capital spending not being fully offset by related increases in the Standardized Measure on our earlier stage U.S. growth assets, along with declines in the trailing 12-month average natural gas price during 2012. No impairments were recorded in the Canadian cost center in the comparative periods.

Marketable Securities

During 2013 we sold marketable securities for proceeds of $2.5 million recognizing a gain of $0.4 million. During 2012 we sold securities, the most significant being our shares in Laricina Energy Ltd., for net cash proceeds of $146.9 million resulting in a gain of $86.5 million.

Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods.

We have estimated the net present value of our asset retirement obligation to be $291.8 million at December 31, 2013 compared to $256.1 million at December 31, 2012. Our overall liability increased year-over-year primarily due to higher cost estimates along with a decrease in the weighted credit-adjusted risk free rate used to calculate the present value of the liability, which decreased to 5.96% at December 31, 2013 from 6.15% at December 31, 2012. See Note 9 for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2013 we spent $16.6 million (2012 – $19.9 million; 2011 – $21.7 million) on our asset retirement obligations and we expect to spend approximately $26.6 million in 2014. Our abandonment and reclamation costs are expected to be incurred over the next 66 years with the majority between 2024 and 2053. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any reclamation or abandonment costs are anticipated to be funded out of cash flow.

Taxes

Income Tax ($ millions)	**2013**	**2012**	**2011**
Current tax expense/(recovery)	$ 7.9	$ 1.6	$ 81.2
Deferred tax expense/(recovery)	30.7	(274.6)	(163.6)
Total tax expense/(recovery)	$ 38.6	$ (273.0)	$ (82.4)

Our current tax expense is comprised mainly of Alternative Minimum Tax ("AMT") payable with respect to our U.S. subsidiary. We expect to recover AMT in future years as an offset to regular U.S. income taxes otherwise payable.

2013 versus 2012

Total tax expense in 2013 was $38.6 million compared to a recovery of $273.0 million in 2012. The increase in tax is primarily related to higher net income in 2013 compared to 2012, which included $781.1 million in non-cash ceiling test impairments in our U.S. cost center.

2012 versus 2011

The increased tax recovery of $273.0 million in 2012 compared to $82.4 million in 2011 relates primarily to the decrease in net income in 2012 due to non-cash ceiling test impairments in our U.S. cost center. Our current taxes were higher in 2011 due to our Marcellus property disposition and resulting gain for income tax purposes.

2014 Guidance

We expect to pay U.S. cash taxes (AMT) of approximately 3-5% of U.S. funds flow in 2014 and 2015. We currently do not expect to pay material cash taxes in Canada until after 2018. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and divestment activity.

Tax Pools

Our estimated tax pools at December 31, 2013 and 2012 are as follows:

Pool Type ($ millions)	2013	2012
Canada		
Canadian oil and gas property expenditures ("COGPE")	$ 111	$ 315
Canadian development expenditures ("CDE")	365	316
Canadian exploration expenditures ("CEE")	224	216
Undepreciated capital costs ("UCC")	295	375
Non-capital losses and other credits	459	488
	1,454	1,710
U.S.		
Alternative minimum tax credit ("AMT")	99	84
Net operating losses	463	462
Depletable and depreciable assets	1,253	1,048
	1,815	1,594
Total tax pools and credits	$ 3,269	$ 3,304
Capital losses – Canada	$ 1,208	$ 1,212

Capital losses reflect the balance of unused capital losses available for carry-forward in Canada. These capital losses have an indefinite carry-forward period however can only be used to offset capital gains.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

	Year ended December 31, 2013			Year ended December 31, 2012		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	17,862	20,388	38,250	20,647	15,862	36,509
Natural gas liquids (bbls/day)	2,801	671	3,472	3,244	383	3,627
Natural gas (Mcf/day)	175,876	112,547	288,423	198,356	53,417	251,773
Total average daily production (BOE/day)	49,976	39,817	89,793	56,950	25,148	82,098
Pricing[2]						
Crude oil (per bbl)	$ 77.67	$ 89.52	$ 83.99	$ 75.21	$ 82.08	$ 78.19
Natural gas liquids (per bbl)	55.51	38.64	52.25	54.86	37.35	53.01
Natural gas (per Mcf)	3.01	3.66	3.26	2.17	3.21	2.39
Capital Expenditures						
Capital spending	$ 286.5	$ 394.9	$ 681.4	$ 255.4	$ 598.0	$ 853.4
Acquisitions	44.4	200.4	244.8	13.6	171.7	185.3
Divestments	(323.2)	(41.9)	(365.1)	(253.9)	(21.9)	(275.8)
Revenues						
Oil and natural gas sales[2]	$ 758.2	$ 818.7	$ 1,576.9	$ 794.1	$ 544.9	$ 1,339.0
Commodity derivative instruments gain/(loss)	(41.9)	–	(41.9)	92.0	–	92.0
Expenses						
Operating	$ 259.1	$ 84.3	$ 343.4	$ 266.3	$ 52.7	$ 319.0
Royalties	105.8	158.5	264.3	109.9	102.3	212.2
Production taxes	10.1	60.3	70.4	11.6	45.0	56.6
General and administrative	92.4	17.9	110.3	78.9	14.9	93.8
DDA&A	300.5	292.7	593.2	322.1	238.2	560.3
Impairments	–	–	–	–	781.1	781.1
Current income tax expense/(recovery)	(0.6)	8.5	7.9	(2.1)	3.7	1.6

(1) Company interest volumes.
(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2013	2012	2011
Oil and natural gas sales[(1)]	$ 1,576.9	$ 1,339.0	$ 1,343.1
Net income/(loss)	48.0	(270.7)	12.8
Per share (Basic)	0.24	(1.38)	0.07
Per share (Diluted)	0.24	(1.38)	0.07
Funds flow	754.2	644.5	574.4
Per share (Basic)	3.76	3.29	3.19
Cash and stock dividends[(2)]	216.9	301.6	388.9
Per share (Basic)[(2)]	1.08	1.54	2.16
Total assets	3,681.8	3,618.4	3,856.1
Long-term debt, net of cash[(3)]	1,022.3	1,064.4	901.5

(1) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.
(2) Calculated based on dividends paid or payable. Cash and stock dividends to shareholders per share may not correspond to actual dividends as a result of using the annual weighted average shares outstanding.
(3) Including current portion of long-term debt.

2013 versus 2012

Oil and gas sales increased in 2013 due to higher realized crude oil and natural gas prices and increased production volumes.

Net income and funds flow improved over 2012 due to increased production volumes and higher realized prices. Net income in 2012 was also impacted by non-cash asset impairment charges.

Cash and stock dividends were lower in 2013 than 2012 due to the reduction in our monthly dividend from $0.18 per month to $0.09 per month, effective in July 2012.

2012 versus 2011

Oil and gas sales were relatively flat for 2012 compared to 2011 as higher production volumes offset the impact of lower realized commodity prices. In 2012 we recorded a net loss of $270.7 million, primarily due to non-cash asset impairment charges.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales[(1)]	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2013				
Fourth Quarter	$ 379.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	432.7	(3.7)	(0.02)	(0.02)
Second Quarter	398.6	38.5	0.19	0.19
First Quarter	366.2	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,576.9	$ 48.0	$ 0.24	$ 0.24
2012				
Fourth Quarter	$ 360.7	$ 34.6	$ 0.18	$ 0.18
Third Quarter	324.9	(88.6)	(0.45)	(0.45)
Second Quarter	314.4	(41.9)	(0.21)	(0.21)
First Quarter	339.0	(174.8)	(0.92)	(0.92)
Total 2012	$ 1,339.0	$ (270.7)	$ (1.38)	$ (1.38)

(1) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

Oil and gas sales increased through the third quarter of 2013 mainly due to strengthening crude oil prices and increased natural gas production in the Marcellus. While we continued to see strong production growth from our Marcellus assets in the fourth quarter, realized crude oil pricing weakened contributing to a decrease in oil and gas sales. During 2012 oil and gas sales were relatively flat compared to 2011 as increased production volumes were offset by lower realized commodity prices.

Net income for 2013 and 2012 was impacted by fluctuating risk management costs, asset impairment charges, gains on marketable security divestments and resulting tax provisions.

LIQUIDITY AND CAPITAL RESOURCES

In 2013 we continued to maintain our liquidity and financial flexibility through an increased focus on cost efficiencies, a disciplined capital program, and the sale of non-core properties. We closed the year in a strong financial position with approximately 80% of our bank credit facility undrawn and a trailing 12-month debt to funds flow ratio of 1.4x.

Total debt net of cash at December 31, 2013, including the current portion, was $1,022.3 million compared to $1,064.4 million at December 31, 2012. Total debt was comprised of $214.4 million of bank indebtedness and $810.9 million of senior notes less $3.0 million in cash. Our working capital deficiency, excluding cash and current deferred financial and tax assets and credits, increased to $271.4 million at December 31, 2013 from $173.2 million at December 31, 2012. The increase in our working capital deficit resulted from increased accounts payable balances due to timing of capital spending compared to the fourth quarter of 2012. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as dividends, net of our SDP and DRIP proceeds, plus capital spending and office capital, divided by funds flow, was 114% for 2013 compared to 174% in 2012. The decrease in our adjusted payout ratio was a result of increased funds flow over the prior year along with reduced capital spending and the reduction in our monthly dividend mid-2012.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	December 31, 2013	December 31, 2012
Long-term debt to funds flow (trailing 12-month)(1)	1.4 x	1.7 x
Funds flow to interest expense (trailing 12-month)(2)	13.3 x	12.1 x
Long-term debt to long-term debt plus equity(1)	35%	35%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) Interest expense excluding non-cash items.

On November 8, 2013, our $1.0 billion bank credit facility was extended for one year, maturing October 31, 2016. Drawn and undrawn fees improved by 10 basis points across the grid and range between 150 and 315 basis points over Bankers' Acceptance rates. We are currently paying 170 basis points over Bankers' Acceptance rates, which are trading around 1.2%, for a combined rate of approximately 2.9%. At December 31, 2013 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

Counterparty Credit

OIL AND GAS SALES COUNTERPARTIES

Our oil and gas receivables are with customers in the oil and gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' creditworthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we obtain financial assurances such as letters of credit, parental guarantees or third party insurance to mitigate some of our credit risk. This process is utilized for both our oil and gas sales counterparties as well as our financial derivative counterparties.

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. At December 31, 2013 we had $28.5 million in mark-to-market assets offset by $37.0 million of mark-to-market liabilities resulting in a net liability position of $8.5 million.

Dividends

($ millions, except per share amounts)		2013		2012		2011
Cash dividends[1]	$	170.7	$	278.0	$	388.9
Stock Dividend Plan		46.2		23.6		–
Total dividends to shareholders	$	216.9	$	301.6	$	388.9
Per weighted average share (Basic)	$	1.08	$	1.54	$	2.16

(1) Includes DRIP of $19.2 million in 2012 and $52.4 million in 2011.

We reported a total of $216.9 million or $1.08 per share in dividends to our shareholders in 2013. Dividends during 2012 were $301.6 million or $1.54 per share and during 2011 were $388.9 million or $2.16 per share. We reduced our monthly dividend from $0.18 per share to $0.09 per share, effective for our July 20, 2012 dividend payment. We will continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions and do not anticipate any changes to our dividend at this time.

Participation in the Stock Dividend Plan ("SDP") is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. Currently we have a participation rate of approximately 23% or approximately $4.2 million per month. The SDP serves as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends.

Commitments

As at December 31, 2013 we had the following minimum annual commitments including long-term debt:

			Minimum Annual Commitment Each Year									
($ millions)		Total		2014		2015		2016		2017		2018		Total Committed after 2018
Transportation commitments	$	102.7	$	30.4	$	25.5	$	13.4	$	12.0	$	3.5	$	17.9
Processing commitments		50.6		10.2		9.6		9.0		8.2		6.8		6.8
Drilling and completions commitment		11.6		11.6		–		–		–		–		–
Power infrastructure		13.9		4.0		7.9		2.0		–		–		–
Office leases		73.0		13.6		11.8		12.1		12.3		12.45		10.7
Total commitments[(1)(2)]	$	251.8	$	69.8	$	54.8	$	36.5	$	32.5	$	22.8	$	35.4

(1) Crown and surface royalties, production taxes, lease rentals, and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(2) US$ commitments have been converted to CDN$ using the December 31, 2013 foreign exchange rate of 1.0636.

For our U.S. Bakken crude oil we have aggregate term pipeline transportation capacity of approximately 8,500 bbl/day from 2014 until April 2016 with 7,500 bbl/day of that continuing through December 2017.

We have contracted up to 191 MMcf/day of natural gas pipeline capacity, some of it in series, with contract terms that range anywhere from one month to five years.

Our Canadian and U.S. office leases expire in 2019. Annual costs of these lease commitments include rent and operating fees. Our commitments, contingencies and guarantees are more fully described in Note 16.

Subsequent to December 31, 2013 we entered into a long-term agreement with a counterparty to provide NGL fractionation services in Western Canada with potential unmitigated demand charges of approximately $18.9 million over the term of the agreement.

Shareholders' Capital

	2013	2012	2011
Share capital ($ millions)	$ 3,061.8	$ 2,997.7	$ 2,622.0
Common shares outstanding (thousands)	202,758	198,684	181,159
Weighted average shares outstanding (thousands)	200,567	195,633	179,889

During 2013 a total of 4,074,000 shares (2012 – 2,816,000; 2011 – 2,510,000) and $61.0 million of additional equity (2012 – $43.9; 2011 – $64.0 million) was issued pursuant to the SDP, our former DRIP and the stock option plan. For further details see Note 14.

On February 8, 2012 we completed a bought deal equity financing of 14,708,500 common shares at a price of $23.45 per share for gross proceeds of $344.9 million ($330.6 million net of issuance costs).

At December 31, 2013 we had 202,758,000 shares outstanding (2012 – 198,684,000; 2011 – 181,159,000) and at February 20, 2014 we had 203,121,000 shares outstanding.

ENVIRONMENT

We strive to carry out our activities and operations in compliance with all applicable regulations and best industry practices. Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. We set corporate targets and mandates to improve environmental performance and execute environmental initiatives to become more energy efficient and to reduce, reuse and recycle water and minimize waste.

Our Board of Directors' Safety and Social Responsibility ("S&SR") Committee is responsible for review of the policies, performance and continuous improvement of the S&SR management system to ensure that our activities are planned and executed in a safe and responsible manner and to ensure we have adequate systems to support ongoing compliance. We may be subject to environmental and other costs resulting from unknown and unforeseeable environmental impacts arising from our operations. There are inherent risks of spills and pipeline leaks at our operating sites and clean-up costs may be significant. However, we have active site inspection, corrosion risk management and asset integrity management programs to help minimize this risk. In addition, we carry environmental insurance to help mitigate the cost of releases should they occur.

The ongoing uncertainty surrounding the direction from government on regulations affects our ability to proactively manage potential risks and opportunities associated with greenhouse gas emissions. We intend to continue to improve energy efficiencies and proactively manage our emissions.

We use the hydraulic fracturing process in our operations. Government and regulatory agencies continue to frame regulations related to this process. We believe we are in compliance with all current government regulations and industry best practices in the U.S. and Canada. Although Enerplus proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the United States impose more stringent compliance requirements surrounding hydraulic fracturing.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital spending. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Reserves

The process of estimating reserves is critical to several accounting estimates. It requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and gas prices, operating costs and royalty burdens change. Reserve estimates impact net income through depletion, the determination of decommissioning liabilities and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on net income.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and amortized over its useful life. There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserve estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair values of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the oil and gas properties. To determine the fair value of these properties, we and independent evaluators estimate oil and gas reserves and future prices of crude oil and natural gas.

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 2(m) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2013.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, NGLs, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic demand, weather conditions, the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American natural gas, natural gas liquids and crude oil, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the price and availability of alternative fuels and government regulations.

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas and crude oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. Refer to the "Price Risk Management" section for further details on our price risk management program.

Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil, natural gas liquids, and natural gas prices along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserve or resource write-downs.

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with

Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") standards. For U.S. GAAP accounting purposes our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserve evaluations have been conducted on approximately 89.5% of the total proved plus probable value (discounted at 10%) of our reserves at December 31, 2013. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 74% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. crude oil properties. Netherland, Sewell & Associates, Inc. (NSAI) evaluated 100% of our U.S. natural gas and shale gas properties.

The evaluations of contingent resources associated with our Wilrich and Fort Berthold assets were conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of our Marcellus gas reserves and provided the estimate of contingent resources. The contingent resource assessments associated with a portion of our waterflood properties were completed internally by Enerplus' qualified reserve evaluators.

The Reserves Committee and the Board of Directors has reviewed and approved the reserve and resource reports of the independent evaluators.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through issuance of equity and debt in past years. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time.

We are listed on the Toronto and New York stock exchanges and maintain an active investor relations program. We provide continuous disclosure and maintain complete and timely public filings. Nonetheless, our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporately and for the oil and gas sector in general).

Access to Transportation and Processing Capacity

Market access for crude oil, NGLs and natural gas production in Canada and the United States is dependent on our ability to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. Newer resource plays, such as the North Dakota Bakken and the Marcellus shale gas, generally experience a sharp production increase in the area which could exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all of the production from a given region, causing added expense and/or volume curtailments for all shippers. Additionally, the transportation of crude oil by rail may come under closer scrutiny by government regulatory agencies in Canada and the United States. As a result, there may be incremental costs associated with transporting crude oil by rail, and there is a risk that access to rail transport may be constrained, depending upon any changes made to existing rail transport regulations.

We continuously monitor this risk for both the short and longer term through dialogue and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate this risk by contracting for firm pipeline or processing capacity or using other means of transportation, including rail and truck. We maintain a diverse mix of pipeline, rail and trucking transportation options within our portfolio.

Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in a given area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services into 2014, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Title Defects or Litigation

Unforeseen title defects or litigation may result in a loss of entitlement to production, reserves and resources.

Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners; however disputes may arise from time to time with respect to ownership of rights of certain properties or resources.

Regulatory Risk & Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we are subject to a broad range of regulatory requirements that continue to increase both within Canada and the United States.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results.

Specifically with respect to regulations for the reduction of greenhouse gas emissions, the Canadian federal government continues to seek alignment for the regulations to be issued in Canada with those of the United States. Accordingly, while we continue to prepare to meet the potential requirements, the actual cost impact and its materiality to our business remains uncertain.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions and our annual capital development budget are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Health, Safety and Environmental Risk ("HSE")

Health, safety and environmental risks impact our workforce and operating costs and result in the enhancement of our business practices and standards. Certain government and regulatory agencies in Canada and the United States have begun investigating the potential risks associated with hydraulic fracturing including the risk of induced seismicity with the injection of fluid into any reservoir. We expect regulatory frameworks will be amended or continue to emerge in this regard. Although Enerplus proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the United States impose more stringent compliance requirements surrounding hydraulic fracturing. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

Enerplus has established a S&SR team that develops standards and systems to manage health, safety and environmental risks, regulatory compliance and stakeholder engagement for the organization. The actions of the S&SR team are driven in part by a steering committee which is comprised of executives and senior management. All S&SR risks are reviewed regularly by the S&SR committee which is comprised of members of the Board of Directors. The Corporation carries insurance to cover a portion of its property losses, liability and business interruption. At present, the Corporation believes that it is, and expects to continue to be, in compliance with all material applicable environmental laws and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet its ongoing environmental obligations.

Counterparty and Joint Venture Credit Exposure

The volatile commodity price environment increases the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position.

A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities. In certain instances we may be able to aggregate all amounts owing to each other and settle with a single net amount.

See the "Liquidity and Capital Resources" section for further information.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements.

We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the U.S. dollar. However our U.S. capital spending and U.S. debt repayment is negatively impacted with a weak Canadian dollar.

We have hedged our foreign currency exposure on our US$175 million, US$54 million and a portion of our US$225 million senior notes using financial swaps that convert the U.S. denominated debt to Canadian dollar debt. In addition, we have hedged the U.S. dollar interest obligation on our US$175 million notes. At this time we have not entered into any other foreign currency derivatives with respect to our oil and gas sales or our U.S. operations.

Interest Rate Exposure

We have exposure to movements in interest rates and credit markets as changing interest rates affect our borrowing costs and value of investments such as our shares as well as other equity investments.

We monitor the interest rate forward market and have fixed the interest rate on approximately 74% of our debt through our senior notes.

Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may be changed in a manner that adversely affects us or our security holders. Tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.

Cash Flow Sensitivity

The sensitivities below reflect all commodity contracts listed in Note 15 and are based on forward markets as at February 4, 2014. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table[(2)]		**Estimated Effect on 2014 Funds Flow per Share**[(1)]
Change of $0.50 per Mcf in the price of AECO natural gas	$	0.14
Change of US$5.00 per barrel in the price of WTI crude oil	$	0.14
Change of 1,000 BOE/day in production	$	0.02
Change of $0.01 in the US$/CDN$ exchange rate	$	0.04
Change of 1% in interest rate	$	0.02

(1) Assumes 204,039,000 weighted average shares outstanding.

2014 GUIDANCE

A summary of our 2014 guidance is below. This guidance does not include any potential acquisitions or divestments.

Summary of 2014 Expectations	Target
Average annual production	96,000 – 100,000 BOE/day
Capital spending	$760 million
Production mix (volumes)	48% crude oil and liquids, 52% natural gas
Operating costs	$10.25/BOE
Cash G&A expenses	$2.45/BOE
Cash share-based compensation expenses	$0.25/BOE
U.S. Cash taxes (% of U.S. funds flow)	3-5%

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a-15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2013, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on October 1, 2013 and ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("**forward-looking information**"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expected 2014 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged; the results from our drilling program and the timing of related production; future oil and natural gas prices and differentials and our commodity risk management programs; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating costs; capital spending levels in 2014 and its impact on our production level and land holdings; our ability to reallocate funds within our 2014 capital program; potential future asset impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and debt-to-funds-flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; the amount and timing of future debt and equity issuances and expected use of proceeds therefrom; and the amount and timing of future dispositions and acquisitions; and our ability to improve our trading multiple and create significant value for our shareholders.*

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and resource volumes; commodity price and cost assumptions; the *continued availability of adequate debt and/or equity financing and funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; a failure to complete planned asset dispositions on the terms anticipated or at all; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in this MD&A and in our other public filings).

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

EXHIBIT 99.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the use of our reports dated February 20, 2014 relating to the consolidated financial statements of Enerplus Corporation and its subsidiaries and the effectiveness of Enerplus Corporation's internal control over financial reporting appearing in this Annual Report on Form 40-F of Enerplus Corporation for the year ended December 31, 2013.

/s/ Deloitte LLP
Chartered Accountants

Calgary, Canada
February 21, 2014

EXHIBIT 99.5

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of our name in the Annual Report on Form 40-F (the "Annual Report") of Enerplus Corporation (the "Registrant"). We hereby further consent to the inclusion in the Annual Report of the Registrant's Annual Information Form dated February 21, 2014 for the year ended December 31, 2013, which document makes reference to our firm and our reports dated January 29, 2014, evaluating the Registrant's oil, natural gas and natural gas liquids interests effective December 31, 2013.

Calgary, Alberta, Canada
February 20, 2014

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ C.B. KOWALSKI

C.B. Kowalski, P. Eng.
Vice President

EXHIBIT 99.6

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

We hereby consent to the use of our name in the Annual Report on Form 40-F (the "Annual Report") of Enerplus Corporation (the "Registrant"). We hereby further consent to the inclusion in the Annual Report of the Registrant's Annual Information Form dated February 21, 2014 for the year ended December 31, 2013 which document makes reference to our firm and our reports dated January 27, 2014 and January 28, 2014, evaluating the Registrant's oil, natural gas, natural gas liquids, and shale gas interests effective December 31, 2013.

Dallas, Texas
February 21, 2014

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ G. LANCE BINDER

G. Lance Binder
Executive Vice President

EXHIBIT 99.7

CERTIFICATION

I, Ian C. Dundas, certify that:

1. I have reviewed this annual report on Form 40-F of Enerplus Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 21, 2014

/s/ IAN C. DUNDAS

Ian C. Dundas
President and Chief Executive Officer
of Enerplus Corporation

EXHIBIT 99.8

CERTIFICATION

I, Robert J. Waters, certify that:

1. I have reviewed this annual report on Form 40-F of Enerplus Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: February 21, 2014

/s/ ROBERT J. WATERS

Robert J. Waters
Senior Vice President and
Chief Financial Officer of Enerplus Corporation

EXHIBIT 99.9

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Enerplus Corporation (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Ian C. Dundas, President and Chief Executive Officer of the Corporation, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

/s/ IAN C. DUNDAS

Ian C. Dundas
President and Chief Executive Officer
of Enerplus Corporation

February 21, 2014

The foregoing certification shall not be deemed "filed" for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the registrant specifically incorporates it by reference.

EXHIBIT 99.10

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Enerplus Corporation (the "Corporation") on Form 40-F for the fiscal year ended December 31, 2013 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert J. Waters, Senior Vice President and Chief Financial Officer of the Corporation certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Corporation.

/s/ ROBERT J. WATERS

Robert J. Waters
Senior Vice President and
Chief Financial Officer of Enerplus Corporation

February 21, 2014

The foregoing certification shall not be deemed "filed" for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of that section. Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act, except to the extent that the registrant specifically incorporates it by reference.

EXHIBIT 99.11

CODE OF BUSINESS CONDUCT

The Code of Business Conduct is our guide to ethical and lawful conduct in our daily business. It requires all of us, from members of our board of directors to new hires, to adhere to a level of ethical business conduct well in excess of the legal minimum. Our compliance with both the letter and spirit of the Code of Business Conduct is essential to protecting Enerplus' business and reputation.

INTRODUCTION

Enerplus' Commitment

Enerplus Corporation and all of its affiliates ("Enerplus" or the "Corporation") is committed to maintaining the highest of business standards in our operations, wherever they may be. We recognize the importance of credibility, integrity, and trust to our success as a business.

Purpose and Applicability of the Code

This Code of Business Conduct summarizes a number of Enerplus policies for appropriate behaviour and applies to all employees, consultants, officers and directors of Enerplus (hereinafter, "Employees"). Accordingly, each of us must comply with the terms of this Code. The Code will help us meet our business practice standards and comply with applicable laws and regulations. It is essential that this Code of Business Conduct be observed. The Code is very important to protecting Enerplus' business and reputation.

The Code of Business Conduct is a general guideline for making certain that:

- A work environment is maintained that promotes the dignity and self-respect of each Employee.
- All Employees are aware of and fully observe the laws and regulations that impact their business activities.
- A standard of behaviour is in place that reflects the values and integrity of Enerplus and its Employees.
- Enerplus is protected from financial loss and legal liability.

This Code of Business Conduct does not replace any other published rules and policies of Enerplus, including other work rules and personal conduct policies. All Enerplus policies and standards are subject to this Code. While this Code of Business Conduct provides guidance and explains what is considered unacceptable behaviour, the Code of Business Conduct does not describe every specific act that is unacceptable. If a specific act is missing from the Code, it does not mean that act is acceptable or condoned. Ultimately, we must rely on our judgment about the right thing to do in order to maintain our personal and corporate integrity.

The Code is to be used as a guide for appropriate conduct and to prevent improper conduct. Enerplus will not tolerate any conduct that is unlawful or damaging to Enerplus' reputation.

Employee Responsibilities

All Employees are responsible for reading this entire Code of Business Conduct and ensuring their conduct is consistent with both the letter and the spirit of Enerplus' business practices.

This Code will help Employees deal with specific situations. In some cases, a situation may be so complex or circumstances so unique that additional guidance is needed. If such a situation occurs and is not included in this Code, it is each Employee's duty to contact his/her supervisor or the Human Resources Department immediately. If necessary, the Human Resources Department may refer the matter to the Legal Department for further advice.

This Code and any detailed Enerplus policy statements and procedures will be updated from time to time. All Employees are required to stay informed of any updates and to comply with all requirements.

Management Responsibilities

Managers must exhibit the highest standards of corporate responsibility and business conduct and create a work atmosphere that supports our corporate values and policies, including this Code. It is the duty of each member of management to take into account an Employee's willingness and commitment to comply with this Code when making promotion and other employment decisions.

Compliance Requirements

Employees must work honestly and in good faith. Employment with Enerplus depends upon an Employee's ability and willingness to comply with this Code. Adherence to these standards carries the highest priority. All Employees are required to acknowledge compliance when they are hired and again on an annual basis.

GLOBAL BUSINESS CONDUCT GUIDELINES

Our Employees

Discrimination, Bullying and Workplace Harassment

Employees are forbidden to discriminate against, bully or harass other Employees, in keeping with our Harassment Policy. No Employee is permitted to act in a way that is considered or could be considered illegal or harassing.

It is the responsibility of each member of management to be aware of any behaviour or conduct that could be considered workplace harassment, bullying or discrimination. Management also is required to enforce these policies and immediately contact the Human Resources Department regarding any situation that could be considered workplace harassment, bullying or discrimination.

It is the responsibility of each Employee to maintain a work environment free of discrimination, bullying and harassment and to report any situation that the Employee believes may be workplace harassment, bullying or discrimination to his/her supervisor, department head or the Human Resources Department.

Employment of Family Members

Enerplus allows an Employee's spouse, parents, children, and other family members to work for Enerplus, both during and after the employee's career with Enerplus, provided the employment is in Enerplus' best interest. Family relationships, however, will not be considered in hiring decisions. All Enerplus hiring decisions will be made strictly on the basis of individual qualifications. To avoid the possibility or appearance of preferential treatment, Enerplus will not have one family member placed in a position of influence over another family member.

Workplace Health and Safety

The health and safety of our personnel and the safe operation of our facilities are principal objectives of Enerplus. We are committed to providing safe and healthy places of employment and will follow operating practices that eliminate or minimize exposure to hazardous or unhealthy conditions. The success of our health and safety efforts depends upon the cooperation, support, and active involvement of all Enerplus personnel. Each Employee is responsible for working safely and complying with all safety rules and protocols at all times. We are committed to maintaining a safe and secure work environment. Threats, intimidation, harassment, assaults, and acts of violence are unacceptable and will not be tolerated.

Employees should refer to the Safety & Social Responsibility section of the Enerplus website for our Health and Safety Policy and minimum safety standards. Questions or concerns should be reported immediately to a supervisor, the Safety & Social Responsibility Department or the Human Resources Department.

<u>Prohibited Items</u>

The use, sale, possession or distribution of illegal drugs, or the improper use of alcohol or prescription drugs, by Employees is strictly forbidden while on Enerplus premises, in Enerplus vehicles, or while conducting Enerplus business on or off Enerplus premises. The use of alcohol is prohibited to the extent that it has a detrimental effect on job performance, safety, or efficiency while conducting Enerplus business on or off Enerplus premises, or while in Enerplus owned or leased vehicles or personal vehicles used for Enerplus business. The approval of an Enerplus officer is required to consume or possess alcoholic beverages on Enerplus premises. Consumption or possession of alcohol in Enerplus owned or leased vehicles or personal vehicles used for Enerplus business is strictly prohibited. For further information, please refer to the Alcohol and Drug Policy.

The possession, use, or distribution of firearms, weapons, and explosives is prohibited while on Enerplus premises, while conducting Enerplus business, or while in Enerplus vehicles on or off Enerplus premises, except as authorized under the Firearm Storage, Transportation and Use Standard found on the Safety & Social Responsibility section of the Enerplus website.

If evidence supports a reasonable suspicion of use, possession, or distribution of prohibited items, Enerplus reserves the right to conduct searches on Enerplus premises or in Enerplus owned or leased vehicles for such items.

Our Company

<u>Document Retention</u>

Employees must comply with Enerplus' department-specific document (physical and electronic) retention guidelines to ensure that all applicable laws and regulations are met. Each Employee should become familiar with and adhere to these guidelines. Additionally, when litigation or an investigation is pending, Employees are prohibited from modifying or destroying relevant documents or records, including Employees' personal files and electronic records. The consequences of modifying or destroying any relevant documents or records are severe and may include prosecution. An Employee who has any doubt about the legality or propriety of modifying or destroying any document or record should contact his/her supervisor or General Counsel before proceeding.

Employees should refer to the Records & Document Management Policy and the Records & Document Management section of the Enerplus website for further department-specific guidelines.

<u>External Communications</u>

From time to time, Employees may be contacted by government representatives or legal counsel representing other companies, government agencies, or individuals in connection with investigations that concern Enerplus, its business, clients, Employees, or suppliers. While Enerplus cooperates with all reasonable requests from government agencies and authorities related to Enerplus' business, an Employee receiving a request for information other than what is provided on a routine basis should decline to respond and immediately report the request to his/her supervisor and seek guidance from the Legal Department. Likewise, if an Employee receives a subpoena or other request to testify or produce documents in relation to Enerplus' business, a copy of the subpoena or request should be forwarded immediately to our General Counsel. All information provided should be truthful and accurate. Employees must never mislead any investigator and must never modify or destroy documents or records in response to an investigation.

Disclosure of Corporate Information; Trading Restrictions

Employees must not trade Enerplus securities while in possession of material, non-public corporate information. Employees must not use such material, non-public corporate information for their benefit or the benefit of others. Material corporate information is any information that, if known, might influence a reasonable investor's investment decision to buy, sell, or hold securities of Enerplus. Non-public means any corporate information that has not been released by Enerplus for public dissemination and which is intended to remain confidential until such authorized dissemination. With the exception of disclosure to Enerplus' advisors, Employees should not share material, non-public corporate information with anyone outside Enerplus (including family members) until it has been made public, regardless of how the information may or may not be used. These restrictions also apply to trading in securities of any other company (including, but not limited to, competitors, suppliers, and customers) if an Employee learns of any material, non-public information about that company during the course of his/her employment with Enerplus.

Employees must adhere to blackout restrictions posted on published blackout calendars. Trading blackouts are implemented to ensure that "insiders" do not have the advantage of information that has not been announced to the general investing public. "Insiders" are considered to be anyone who has access to information that has not been released to the public realm. Applicable securities laws dictate the protection of the entire investing public to ensure fairness. Should an individual breach insider trading rules they may be subject to significant penalties by regulatory authorities.

Announcements of material information will include scheduled and unscheduled announcements. Scheduled announcements include the release of quarterly financial statements, annual financial statements and annual reports of Enerplus, and in that regard, trading in Enerplus securities by Employees will be prohibited for a certain time before and after the release of financial statements. Unscheduled announcements may include the release of information relative to changes in the Corporation of a financial or structural nature, which may or may not require trading blackouts.

Management will make every attempt to inform Employees of changes to blackout periods. However, blackout periods may change without notice. Should you have any questions or require clarification regarding trading restrictions, it is your responsibility to direct these questions to General Counsel prior to trading any Enerplus securities.

Employees must report violations or misuse of material, non-public corporate information to our General Counsel immediately.

Directors and officers of Enerplus are required by securities regulations to make certain filings with securities commissions to report their holdings and transactions in Enerplus' securities. Questions about these laws should be directed to the General Counsel.

Directors and officers of Enerplus may not, directly or indirectly, buy, sell or enter into:

- any short sale of securities of Enerplus;
- any puts, call options or other rights or obligations to buy or sell securities of Enerplus;
- any derivative instruments, agreements or securities, the market price, value or payment obligations of which are derived from or based on the value of securities of Enerplus; or
- any other derivative instruments, agreements, arrangements or understanding (commonly known as equity monetization transactions) the effect of which is to alter, directly or indirectly, the director's or officer's economic interest in securities of Enerplus, or the director's or officer's economic exposure to Enerplus, with the exception of corporate equity hedges or normal course issuer bids.

Enerplus believes that the interests of the Corporation's directors and officers should be aligned with those of the Corporation's other shareholders. Engaging in the above activity frustrates our intention that directors and officers hold a meaningful ownership interest in Enerplus and bear the full risks and rewards of ownership.

Conflicts of Interest

Employees are not permitted to do anything that does not support the best interests of Enerplus. For example:

- An Employee should not use Enerplus property for his/her own material benefit.
- An Employee should not influence Enerplus' contractors or consultants for his/her own personal gain.
- An Employee, or his/her family members or friends, should not act on business opportunities or investments presented to Enerplus, other than for the benefit of the Corporation, that are not available to the public, without written permission from General Counsel.
- An Employee should not make or recommend decisions for Enerplus that might benefit the Employee, his/her family members, or friends financially.
- An Employee or their spouse should not own a five percent (5%) or more equity interest in any entity that sells supplies, furnishes services, or otherwise does business with Enerplus without written permission from General Counsel.
- An Employee or their spouse should not own a five percent (5%) or more equity interest in any entity that is a competitor of Enerplus without disclosing such interest.

Before acknowledging compliance with this Code, an Employee must report in writing any conflicts of interest to the Human Resources Department. If conflicts of interest arise after the Employee has acknowledged compliance, the Employee must report the conflicts immediately in writing to the Human Resources Department, which will disclose such conflicts to General Counsel.

During business hours, Employees should devote their full time and attention to Enerplus and their assigned job duties. Unrelated outside activities, business, or secondary employment are not permitted during business hours.

With the exception of Enerplus directors, no Employee of Enerplus should serve on the executive or board of any corporation that Enerplus does not control or have an ownership interest in without the written approval of Enerplus' President and CEO. It is acceptable to serve on the board of a non-profit, charitable, religious, or civic organization without prior written approval, provided it does not interfere with or impair the Employee's ability to perform their duties at Enerplus and represents a commitment of personal time.

To avoid potential conflicts of interest, it is against Enerplus' policy for Enerplus to extend loans to officers or directors. It is acceptable, however, for Enerplus to extend loans to Employees in certain instances (e.g. loans to purchase personal computers).

Confidential and Proprietary Information

Occasionally, Employees may know confidential information concerning Enerplus' business, including customers, suppliers, business contacts, Employees, or technical operations. Employees must keep this information confidential during and after their employment with Enerplus. Personal information relating to Enerplus customers, suppliers, business contacts or Employees must be treated in accordance with Enerplus' Privacy Policy.

Generally, any information stored by and/or processed by Enerplus is proprietary information. This confidential information includes computerized data, methods, techniques, and documentation relating to Enerplus' computing services, developed software, and third-party software.

Employees must be aware of their responsibilities regarding access to Enerplus' computer services, and the access, use, and disclosure of confidential information. Confidential and proprietary information must be used for Enerplus purposes only, never for personal gain. Enerplus prohibits Employees from releasing or misusing any confidential and proprietary Enerplus information.

Accounting and Reporting

Accurate documents are important during audits and other internal or external reviews. All Employees must comply with Enerplus' accounting and reporting procedures and make sure all books, records, accounts, and supporting papers are accurate and complete. Employees are forbidden to forge, falsify, or intentionally leave out important facts on any business documents of Enerplus which could mislead auditors or other internal or external reviewers.

Expense Accounts

Employee expense accounts are to be used only to reimburse Employees for items and activities that are purchased for Enerplus business. Employees must submit accurate expense reports of the money spent for this purpose.

Enerplus' Information Technology Resources

Corporate information, information systems and electronic communications are considered assets and valuable resources to Enerplus. Enerplus requires the appropriate use of these assets and their protection in a manner commensurate with their sensitivity, value and criticality. Any electronic communication of personal information must be in accordance with Enerplus' Privacy Policy.

All Employees are required to:

- Manage and protect corporate information, information systems and electronic communications in accordance with all Enerplus policies, standards and procedures, including statutory and regulatory requirements;

- Take accountability for appropriate security, access and retention of specific information they are responsible for; and

- Report incidents and assist in investigations relating to the misuse of information assets.

Enerplus' information technology resources, such as email and internet access, are provided to Employees in pursuit of Enerplus' business. While limited personal use of these resources is acceptable, Employees should not expect their use of these resources to be private or confidential. Personal use of these resources, such as accessing social networking/media websites (e.g. Facebook, Twitter, YouTube, etc.), also should not interfere with Employee productivity or business processes.

Employees should take the same care in their electronic communications as they take when they communicate in person or by paper. Information and data are at risk when transmitted over the internet.

Employees shall not use Enerplus' information technology resources inappropriately, including the following prohibited activities:

- Accessing, viewing, downloading, storing or redistributing any material or message that is illegal or offensive;

- Activities designed to evade, compromise or otherwise exploit security controls;
- Possession or use of assessment and discovery tools that could be used to collect information to compromise the security of Enerplus' information system or launch attacks against other parties' information systems;
- The intentional creation and/or transmission of malicious code (viruses, worms, etc.);
- Malicious activity including, but not limited to: erasing, renaming or making unusable any software, data or information;
- Disclosing, gathering or using another Employee's account/password to access any information technology resources;
- Participation in chain letters or other forms of mass mailing or marketing; or
- Connecting non-Enerplus/personal devices (laptops, external hard/flash drives, etc.) directly to an Enerplus device or network unless authorized by the Information Services Department.

Enerplus does not allow Employees to copy or distribute copyrighted materials (e.g., software, database files, articles, graphics, music, movies, etc.) through Enerplus' email system or by any other means without confirming in advance from appropriate sources that Enerplus has the right to copy or distribute the material. Employees are not permitted to install any software on Enerplus' information systems without the express written consent of an executive with responsibility for the Information Services Department.

An Employee's logon IDs and passwords are intended for his/her use only and each Employee is responsible for all activity that occurs under their accounts. Employees must protect their accounts through the use of strong passwords.

Enerplus may access its information technology resources at any time as part of an internal audit or to investigate suspected unauthorized use, and may disclose the information it accesses to law enforcement or other third parties without prior consent of the sender or the recipient.

Employees should consult the Information Services Security Policy and the Information Services Security section of the Enerplus website for further policies, responsibilities, guidance and awareness related to information security.

Internet/Intranet Site Development

Enerplus' internet and intranet are important platforms to communicate Enerplus information to Employees, customers, and the public.

As such, the Corporation's Information Services Department and the Corporate & Investor Relations Department shall be solely responsible for and shall administer the creation and development of all company internet and intranet sites and content. However, any Employee or stakeholder suggestions for enhancement to the sites are encouraged.

Company Logo

The logos of Enerplus and its business units are considered property of Enerplus and must only be used for business purposes. Only the approved logos, which are available through the Corporate & Investor Relations Department, may be used, and approval must be obtained from an executive with responsibility for this department prior to using any Enerplus logo. Re-creation or alteration of Enerplus' logos is not permitted. Furthermore, all logo items, such as apparel and office items, must be purchased through Corporate & Investor Relations.

Our Business Partners and Customers

Relationships with Contractors and Suppliers

Contractor and supplier relationships must be managed in a fair, equitable, and ethical manner consistent with this Code of Business Conduct, all applicable laws, and good business practices.

Enerplus promotes competitive procurement to the maximum extent practical and evaluates every supplier's products and services on the basis of technical excellence, quality, reliability, service, price, delivery, and other relevant objective factors. Enerplus prohibits Employees from making purchasing decisions on the basis of personal relationships, friendships, or the opportunity for personal financial gain.

Employees must respect the terms of supplier and contractor contracts and licensing agreements and safeguard all confidential information received from a contractor or supplier, including pricing, technology, or proprietary design information. This confidential information must not be disclosed to anyone outside Enerplus without the written permission of the supplier or contractor.

All contractors who exchange or receive personal information from Enerplus must have privacy policies and practices in compliance with applicable Canadian and United States federal, provincial and state laws.

Anti-Corruption

Enerplus is committed to honesty and integrity in all of its business operations and will actively avoid corruption. We recognize that we may operate in jurisdictions which have different standards of ethical behaviour. Regardless of location, Employees shall carry out their duties in accordance with the principles set out in this Code and, specifically, will comply with all applicable anti-bribery and fair practices legislation.

Acts of corruption, either direct or indirect, are prohibited. Accordingly, Employees shall not engage in any acts that are improper or could appear to be improper, including the following:

- Paying bribes or kickbacks to, or accepting bribes or kickbacks from, public officials or private individuals;
- Making facilitation payments;
- Failing to keep complete and accurate records of transactions;
- Approving payment of invoices or expenses without proper back-up or scrutiny;
- Engaging in joint ventures or retaining agents or consultants to deal with public officials without conducting adequate due diligence of the counterparty's previous activities or reputation.

Compliance with these principles will ensure that Enerplus' business activities are transparent and our commercial relationships are based upon honesty and fairness.

Gifts and Entertainment

Reasonable gifts and entertainment are a part of normal business courtesy and are not prohibited. In many cultures, exchanging gifts or entertainment is designed to foster trust in a business relationship. However, Employees should always use good judgment and discretion to avoid the appearance of impropriety or obligation. Enerplus Employees should be certain that any gifts given or received, or entertainment hosted or attended as a guest, do not violate the law, customary business practices, or this Code of Business Conduct.

While Employees may exchange or accept gifts with their customers and suppliers as part of normal business courtesy, no gift, favor, or payment should be accepted which imparts a future obligation on the Employee or was given in an attempt to influence decisions regarding the business of Enerplus. Additionally, the value of the gifts exchanged should be reasonable, and the exchanges should occur infrequently.

Likewise, while Employees may be participants in entertainment with their customers and suppliers as hosts or guests in the normal course of a business relationship, Employees must not be participants when the entertainment is an attempt to influence decisions regarding the business of Enerplus or imparts a future obligation on the Employee. Additionally, the value of the entertainment should be reasonable and the Employee's participation should occur infrequently. Finally, Employees are prohibited from participating in inappropriate entertainment as either a guest or a host.

Gifts and entertainment in excess of $200 may be accepted, if approved in advance by an executive officer. If a gift has been received but, given the circumstances, the gift is determined to be inappropriate, your manager may require the gift be returned to the originator. An Employee who has any doubt about the propriety of a gift or entertainment should contact his/her supervisor or the Human Resources Department before accepting the gift or participating in the proposed activity.

Obtaining and Using Competitor Information

While information about our competitors, customers, and suppliers is a valuable asset, the law and our standards of appropriate business conduct require that our Employees obtain this information legally. It is not unusual to obtain information about other organizations, including our competitors, through legal and ethical means such as public documents, public presentations, journal and magazine articles, and other published and spoken information. However, Employees are prohibited from obtaining proprietary or confidential information about our competitors, customers, or suppliers through illegal means, or from using any proprietary or confidential information acquired during a prior employment relationship. It is also not acceptable to use or seek to acquire proprietary or confidential information when doing so would require anyone to violate a contractual arrangement, such as a confidentiality agreement with a prior employer. Employees are prohibited from taking any improper actions to gain information about our competitors, customers, and suppliers.

Our Communities

Environmental Compliance

Enerplus is dedicated to complying with all relevant environmental laws and regulations and requires Employees to comply with these laws and regulations as well. It is the duty of each Employee to report what he/she believes to be environmental violations to his/her supervisor or the Safety & Social Responsibility Department. For further information, please refer to the Environment Policy.

Political Contributions

Only Enerplus' President and CEO may authorize use of the Corporation's resources to support political activities. Employees must not use Enerplus' money, credit, property, or services for political activities. Outside of Enerplus business hours, Employees may participate in any political activities of their choice, but Enerplus will not support or reimburse Employees financially.

Requests for Information from the Media and Public

Only Enerplus' President and CEO and the Corporate & Investor Relations Department are authorized to work with the media directly. When Enerplus provides information to the news media, Enerplus has the obligation to report accurately and completely all related material facts. In order to ensure that Enerplus complies with its obligations, Employees who are contacted by the media for information regarding Enerplus' business activities and plans, financial information, or Enerplus' position on public issues, must refer the request to the Corporate & Investor Relations Department. Likewise, all requests from the media for interviews must be directed to Corporate & Investor Relations. Employees may not answer any questions from any member of the media unless they have participated in Enerplus' media training program and consulted with the Corporate & Investor Relations Department.

Press Releases

Press releases allow Enerplus to announce important and relevant information to the public through the media. If a business unit or department within Enerplus anticipates the necessity for a press release to be created, the business unit or department must contact the Corporate & Investor Relations Department to discuss the appropriateness of such a release and to provide the needed information. All press releases must be written and issued by the Corporate & Investor Relations Department and are subject to application of the Disclosure Policy protocols.

Public Speaking and Publishing Articles

Speeches and articles offer excellent opportunities for Enerplus and its Employees to present topics, ideas, and information of interest to business and professional audiences. These communications provide the public with a clearer understanding of Enerplus and its various business units. A speech or article on a professional topic written by an Employee for delivery to an audience or publication represents Enerplus. Speeches and articles must be approved by the Corporate & Investor Relations Department prior to the speaking engagement or submission for publication.

Social Networking and Blogs

Employees have the right to create personal blogs and postings on social networking websites. However, online misconduct can be grounds for discipline, even if it does not occur during business hours or using Enerplus' resources. Inappropriate content for online employee postings includes, but is not limited to, the following:

- Enerplus' confidential or proprietary information;
- Information concerning Enerplus or Employees that would violate this Code or any other Enerplus policies, including the Privacy Policy; and
- Negative comments about Enerplus or Employees, or that would harm the reputation of Enerplus or its Employees.

Community Involvement

Enerplus directly and through its Employees contributes to the general well-being and improvement of towns, cities, and regions where it has operations. Enerplus provides support to worthwhile community programs in areas such as social welfare, health, education, and arts and culture to promote the development of positive relationships in the areas where we have business interests. Enerplus also encourages the recruitment of qualified local personnel where practical. All Enerplus community involvement activities and requests for corporate contributions must be approved by the Corporate & Investor Relations Department in coordination with the Safety & Social Responsibility Department.

While Enerplus encourages Employees to participate in charitable organizations and other community activities of their choice, these outside activities should not interfere with job duties. Accordingly, prior approval from your manager must be obtained when participation is supported by

Enerplus and when utilizing Enerplus resources (including work time, e.g. days of caring). Where participation is on personal time and does not conflict with job duties then approval is not required. No Employee may pressure another Employee to express a view that is contrary to a personal belief or to contribute to or support political, religious, or charitable causes.

Community Projects

When a new project or business issue affects a local community, the business unit should seek the guidance of the Corporate & Investor Relations Department to help facilitate communications with the affected community. The Corporate & Investor Relations Department will serve as support, proactively building and maintaining relationships with local communities as project development occurs. This will include developing a consistent platform to help educate landowners and communities on Enerplus' operations and safety programs.

REPORTING VIOLATIONS AND RESOURCES FOR GUIDANCE

This Code and other Enerplus policies provide general information for seeking guidance or reporting violations of the Code to supervisors, department heads, the Human Resources Department or our General Counsel. For more serious breaches of this Code, or if you have not received a satisfactory response, please refer to the Whistleblower Policy discussed below.

Whistleblower Policy

Enerplus has instituted a Whistleblower Policy to provide for the reporting and review of concerns relating to accounting and auditing matters, as well as other corporate misconduct and breaches of this Code of Business Conduct. Like the Code of Business Conduct, the Whistleblower Policy is designed to encourage ethical behaviour by all Enerplus Employees. Further details, and procedures for submitting a report, are set out in the Whistleblower Policy.

Disciplinary Action

This Code is intended to help Employees conduct themselves in a manner consistent with our values. Employees may face disciplinary action if they:

- Violate this Code
- Encourage or help other Employees to violate this Code
- Condone other Employees who violate this Code
- Fail to report a Code violation
- Conceal a Code violation
- Retaliate against any Employee who reports a Code violation in good faith
- Fail as an officer, director, manager, or supervisor to take appropriate steps to ensure compliance with this Code

Disciplinary action may include one or more of the following:

- A warning
- A written reprimand
- Mandatory reimbursement of losses or damages
- Suspension

- Demotion
- Termination of employment with Enerplus
- Referral for criminal prosecution or civil action

Management has the discretion to determine the level and type of discipline that is appropriate in any given circumstance. For more information please refer to the Progressive Discipline Procedure.

<u>Monitoring</u>

Enerplus will monitor compliance with its policies and procedures, including this Code.

<u>Questions/Effect of this Code of Business Conduct</u>

This Code is not a comprehensive listing of every Enerplus policy or applicable law. If questions arise about what this Code means or how it should be applied, Employees should contact their supervisor, department head or the Human Resources Department.

Sources of Information

VP, Human Resources	(403) 298-8902
VP, Information Services	(403) 693-4960
Manager, Safety & Social Responsibility	(403) 693-5054
VP, General Counsel & Corporate Secretary	(403) 298-4413