encana

news release

Encana delivers on its targets in a year of change, well positioned for 2014

Calgary, Alberta (February 13, 2014) **TSX, NYSE: ECA**

Encana Corporation (TSX: ECA) (NYSE: ECA) concluded 2013 by meeting or exceeding guidance on all of its key operating and financial metrics during a year in which it announced a new President & CEO and launched a bold change in its strategy. Solid results have already been achieved on primary themes of the strategy announced by the company in the fourth quarter, including significant year-over-year increases in liquids production and ending the year with strong cash flow and a strong balance sheet.

"The fourth quarter of 2013 was a transformational time for Encana. In a six-week window, we launched our new strategy, completed an organizational restructuring and announced our 2014 budget. These are significant accomplishments and I'm proud of the way our team performed during that time," says Doug Suttles, Encana's President & CEO. "We finished 2013 strong and we're well positioned to deliver on our priorities and objectives in 2014 with our new strategy very much underway."

Liquids output in the fourth quarter of 2013 averaged 66,000 barrels per day (bbls/d), an 82 percent increase when compared to the fourth quarter of 2012. Encana averaged 53,900 bbls/d of full-year liquids production, a 74 percent increase compared to 2012. Looking ahead to 2014, Encana forecasts a 30 percent year-over-year increase in total liquids production, offsetting a small decrease in forecasted natural gas production. With its focus being on the development of liquids such as light oil and condensate combined with lowering its cost structures, Encana believes the result will be higher margins and improved netbacks, in line with the company's stated objective to value profitability over production volumes.

Average natural gas production volumes for 2013 were 2,777 million cubic feet per day (MMcf/d), meeting the company's 2013 guidance. Natural gas production is expected to decline slightly in 2014 although forecasted liquids growth will keep production unchanged from 2013 levels on a total equivalency basis.

Encana reached its 2013 production and cash flow targets with total 2013 capital investment coming in at $2.7 billion, representing an approximately $400-million reduction relative to the original capital spending guidance set at the start of the year. The company finished the year reporting annual cash flow of approximately $2.6 billion or $3.50 per share, net earnings of $236 million or $0.32 per share and operating earnings of $802 million or $1.09 per share. For the fourth quarter of 2013, Encana recorded $677 million in cash flow or $0.91 per share and $226 million in operating earnings or $0.31 per share. The fourth-quarter net loss of $251 million was impacted by the result of the change in Encana's unrealized hedging position, a foreign exchange loss as well as higher administrative expense associated with the company's organizational restructuring. Encana ended the year with approximately $2.6 billion in cash and cash equivalents on its balance sheet.

"Hitting our 2013 targets while at the same time reducing our overall capital investment is a reflection of our focus on efficiency and profitability," says Suttles. "There's a sense of renewed energy across our business as we work collectively to become the leading North American resource play company."

Encana's updated 2014 guidance can be downloaded from http://www.encana.com/investors/financial/corporate-guidance.html.

Update on operations activity

- **Duvernay:** Encana is moving into full resource play hub mode in the Kaybob area in the northern portion of the Duvernay, with the first multi-well pad underway with two of the eight planned wells on production. Drilling of the remaining six wells will be initiated in March after construction of the pad is completed. Moving into continuous operations on multi-well pads is a key step in delivering efficient development plans. Encana currently has five rigs running in the Duvernay and continues working towards commerciality in the southern Willesden Green area.
- **Montney:** Encana is currently running nine rigs as the company continues to focus development on the Montney's oil and liquids-rich areas. Encana's fifth multi-well oil pad in Gordondale has been completed.
- **DJ Basin:** Encana now has six rigs running in the DJ, up from two rigs last year, and continues to improve efficiencies. On its most recent well, the company set a record of approximately eight days from spud to rig

release, down from the 13-day average in 2013. Encana also captured a 34 percent reduction in hydraulic fracturing costs over 2013.

- **San Juan Basin:** Encana has one rig running and realized strong production performance on its latest well with a 30-day initial production rate of approximately 450 bbls/d. The company continues to work with the Bureau of Land Management to streamline the permitting process to help with the acceleration of Encana's development in the play.
- **Tuscaloosa Marine Shale:** Encana currently has two rigs running in the play to advance its appraisal program.
- Full commercial production was achieved offshore Nova Scotia at the **Deep Panuke** gas field with the issuance of the Production Acceptance Notice in mid-December, with the platform producing at or near its full capacity of 300 MMcf/d since that time.

Hedging position

As of December 31, 2013, Encana has hedged approximately 2,138 MMcf/d of expected 2014 production at an average price of $4.17 per thousand cubic feet (Mcf) and approximately 825 MMcf/d of expected 2015 production at an average price of $4.37 per Mcf. In addition, Encana has hedged approximately 9.5 thousand barrels per day (Mbbls/d) of expected 2014 oil production using WTI fixed price contracts at an average price of $94.19 per barrel (bbl).

Dividend declared

Encana's Board of Directors has declared a quarterly dividend of $0.07 cents per share payable on March 31, 2014 to common shareholders of record as of March 14, 2014.

For the dividend payable on March 31, 2014 (to holders of common shares as at March 14, 2014) and for all future dividends, Encana's Board of Directors has determined that all common shares distributed to participating shareholders pursuant to the company's dividend reinvestment plan (DRIP) will be issued from Encana's treasury without a discount unless otherwise announced by Encana by way of news release.

Financial Summary				
(for the period ended December 31) ($ millions, except per share amounts)	**Q4 2013**	Q4 2012	**2013**	2012
Cash flow[1]	**677**	809	**2,581**	3,537
Per share diluted	**0.91**	1.10	**3.50**	4.80
Operating earnings[1]	**226**	296	**802**	997
Per share diluted	**0.31**	0.40	**1.09**	1.35
Earnings Reconciliation Summary				
Net earnings (loss)	**(251)**	(80)	**236**	(2,794)
After tax (addition) deduction:				
Unrealized hedging gain (loss)	**(209)**	(72)	**(232)**	(1,002)
Impairments	**-**	(300)	**(16)**	(3,188)
Non-operating foreign exchange gain (loss)	**(124)**	(66)	**(282)**	92
Income tax adjustments	**(80)**	62	**28**	307
Restructuring charges	**(64)**	-	**(64)**	-
Operating earnings[1]	**226**	296	**802**	997
Per share diluted	**0.31**	0.40	**1.09**	1.35

[1] Cash flow and operating earnings are non-GAAP measures as defined in Note 1.

Production Summary						
(for the period ended December 31) (After royalties)	**Q4 2013**	Q4 2012	% Δ	**2013**	2012	% Δ
Natural gas (MMcf/d)	**2,744**	2,948	-7	**2,777**	2,981	-7
Liquids (Mbbls/d)	**66.0**	36.2	82	**53.9**	31.0	74

Natural Gas and Liquids Prices				
	Q4 2013	Q4 2012	**2013**	2012
Natural gas				
NYMEX ($/MMBtu)	3.60	3.40	3.65	2.79
Encana realized natural gas price[1] ($/Mcf)	**4.34**	5.02	**4.09**	4.82
Oil and NGLs ($/bbl)				
WTI	97.46	88.22	97.97	94.21
Encana realized liquids price[1]	**67.01**	66.65	**67.75**	75.12

[1] Realized prices include the impact of financial hedging.

Reserves revisions reflect new strategic focus

The majority of revisions to reserves in 2013 (shown in the following tables) are a result of aligning future capital spending with the new strategy that Encana announced in November.

The Company's focused investment on five of its core oil and natural gas liquids-rich growth plays, resulted in (under U.S. protocols prepared in accordance with the requirements of the United States Securities and Exchange Commission (SEC)) Encana's proved natural gas reserves decreasing 11 percent to approximately 7.9 Tcf, due primarily to dry gas proved undeveloped (PUD) reserves reductions as the company transitions to a more balanced commodity portfolio. Proved liquids reserves increased 5 percent to approximately 220 MMbbls. Overall, Encana's proved reserves as at December 31, 2013 under U.S. protocols decreased 9 percent to approximately 9.2 Tcfe.

2013 Proved Reserves Estimates – United States SEC Protocols (After Royalties)			
Using constant prices and costs; simplified table.	**Natural Gas (Bcf)**	**Liquids (MMbbls)**	**Total (Tcfe)**
December 31, 2012	**8,792**	**210.0**	**10.1**
Extensions & Discoveries	981	55.8	**1.3**
Revisions	(618)	(24.3)	**(0.8)**
Acquisitions	7	0.6	**-**
Divestitures	(296)	(1.6)	**(0.3)**
Production	(1,014)	(19.7)	**(1.1)**
December 31, 2013	**7,852**	**220.8**	**9.2**

On a Canadian protocol basis, Encana's new strategy resulted in the reclassification of PUD reserves to either probable reserves or contingent resources. The bulk of the changes to reserve estimates are due to the timing of funding decisions made by Encana and not a reflection of the performance or quality of the reserves. PUDs account for approximately 36 percent of total proved reserves, an 11 percentage point decrease from year-end 2012 reflecting the company transitioning to a more balanced commodity portfolio. All of the PUDs at December 31, 2013 are scheduled for development within five years.

2013 Proved Reserves Estimates - Canadian Protocols (After Royalties)			
Using forecast prices and costs; simplified table.	**Natural Gas (Bcf)**	**Liquids (MMbbls)**	**Total (Tcfe)**
December 31, 2012	**11,617**	**240.4**	**13.1**
Extensions & Discoveries	772	49.7	**1.1**
Revisions	(2,316)	(33.6)	**(2.6)**
Acquisitions	8	0.7	**-**
Divestitures	(491)	(2.6)	**(0.5)**
Production	(1,014)	(19.7)	**(1.1)**
December 31, 2013	**8,576**	**234.9**	**10.0**

Encana has focused its reserves disclosure on proved reserves based on a forecast or business case basis. In 2010, the company expanded how it reports on its estimates of reserves and resources and published estimates of proved, probable and possible reserves as well as all categories of economic contingent resources. Economic contingent resources fall into three categories: low estimate (1C), best estimate (2C) and high estimate (3C). The three classifications of contingent resources have the same degree of technical certainty as the corresponding reserves categories. In determining their economic viability, the same commodity price assumptions are applied as estimating proved, probable and possible reserves. Contingent resources are not yet commercial due to contingencies such as the timing and pace of development, or the need for additional infrastructure. The low estimate is the most conservative category and carries with it the greatest degree of confidence—90 percent—that these resources will be recovered.

Reserves and Resources (Tcfe, After Royalties)						
	Estimated Reserves			Estimated Economic Contingent Reserves		
Using forecast prices and costs	1P Proved	2P Proved + Probable	3P Proved + Probable + Possible	1C Low Estimate	2C Best Estimate	3C High Estimate
Total As at Dec. 31 2013	10.0	14.7	17.6	29.6	51.3	74.0
Total As at Dec. 31 2012	13.1	20.7	24.3	25.4	45.4	69.8

For information on reserves reporting protocols see Note 2.

Conference call information
Encana will host a conference call today Thursday, February 13, 2014 starting at 7:00 a.m. MT (9:00 a.m. ET). To participate, please dial (888) 231-8191 (toll-free in North America) or (647) 427-7450 approximately 10 minutes prior to the conference call. An archived recording of the call will be available from approximately 12:00 p.m. ET on February 13 until midnight on February 20, 2014 by dialing (855) 859-2056 or (416) 849-0833 and entering passcode 29851719. A live audio webcast of the conference call, including slides, will also be available at www.encana.com, in the *Invest in Us* section under *Presentations & Events*. The webcast will be archived for approximately 90 days.

Media are invited to participate in the call in a listen-only mode.

Follow Encana on Twitter @encana for updates during the company's 2013 fourth quarter and year-end conference call. President & CEO Doug Suttles also discusses the 2013 fourth quarter and year-end results in a new video posted at www.youtube.com/encana.

The unaudited interim Condensed Consolidated Financial Statements for the period ended December 31, 2013 are available at www.encana.com.

Encana Corporation
Encana Corporation ("Encana") is a leading North American energy producer that is focused on developing its strong portfolio of resource plays, held directly and indirectly through its subsidiaries, producing natural gas, oil and natural gas liquids (NGLs). By partnering with employees, community organizations and other businesses, Encana contributes to the strength and sustainability of the communities where it operates. Encana common shares trade on the Toronto and New York stock exchanges under the symbol ECA.

Important Information
Encana reports in U.S. dollars unless otherwise noted. Production, sales and reserves estimates are reported on an after-royalties basis, unless otherwise noted. Per share amounts for cash flow and earnings are on a diluted basis. The term liquids is used to represent oil, NGLs and condensate. The term liquids-rich is used to represent natural gas streams with associated liquids volumes. Unless otherwise specified or the context otherwise requires, reference to Encana or to the company includes reference to subsidiaries of and partnership interests held by Encana Corporation and its subsidiaries.

NOTE 1: Non-GAAP measures
This news release contains references to non-GAAP measures as follows:

- Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and cash tax on sale of assets.
- Operating earnings is a non-GAAP measure defined as net earnings excluding non-recurring or non-cash items that management believes reduces the comparability of the company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, foreign exchange gains/losses, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective tax rate.

These measures have been described and presented in this news release in order to provide shareholders and potential investors with additional information regarding Encana's liquidity and its ability to generate funds to finance its operations.

NOTE 2: Reserves reporting information
Encana's disclosure of reserves data is in accordance with Canadian securities regulatory requirements. Encana's 2013 disclosure includes proved and probable reserves quantities before and after royalties employing forecast prices and costs in accordance with Canadian protocols. Reserves disclosure employing U.S. protocols uses SEC constant prices and costs on proved reserves on an after-royalties basis. Reserves disclosure under both Canadian and U.S. protocols will be available in the Annual Information Form, which the company anticipates filing later this month.

For all Canadian protocol reserves and economic contingent resources estimates highlighted in this news release, Encana has used Henry Hub forecast prices of $4.25 per MMBtu for 2014, $4.50 per MMBtu for 2015, $4.75 per MMBtu for 2016, $5.00 per MMBtu for 2017, $5.25 per MMBtu for 2018, then increasing to $5.97 per MMBtu by 2023 and escalating 2 percent per year thereafter. Encana has used WTI forecast prices of $97.50 per bbl for 2014 through 2019, then increasing to $104.57 per bbl by 2023 and escalating 2 percent per year thereafter.

RESERVES METRICS DEFINITIONS
Proved reserves added in 2014 included both developed and undeveloped quantities. Additions to and removals from Encana's PUD bookings were consistent with Encana's revised strategy. The company estimates that 100 percent of its PUDs will be developed within the next five years. Many performance measures exist; all measures have limitations and historical measures are not necessarily indicative of future performance.

ADVISORY REGARDING RESERVES & OTHER RESOURCES INFORMATION - Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, 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. Proved reserves are those reserves which 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. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

The estimates of economic contingent resources contained in this news release are based on definitions contained in the Canadian Oil and Gas Evaluation Handbook. Contingent resources do not constitute, and should not be confused with, reserves. Contingent resources are defined as those quantities of petroleum 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. Economic contingent resources are those contingent resources that are currently economically recoverable. In examining economic viability, the same fiscal conditions have been applied as in the estimation of reserves. There is a range of uncertainty of estimated recoverable volumes. A low estimate is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate, which under probabilistic methodology reflects a 90 percent confidence level. A best estimate is considered to be a realistic estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, which under probabilistic methodology reflects a 50 percent confidence level. A high estimate is considered to be an optimistic estimate. It is unlikely that the actual remaining quantities recovered will exceed the high estimate, which under probabilistic methodology reflects a 10 percent confidence level.

There is no certainty that it will be commercially viable to produce any portion of the volumes currently classified as economic contingent resources. The primary contingencies which currently prevent the classification of Encana's disclosed economic contingent resources as reserves include the lack of a reasonable expectation that all internal and external approvals will be forthcoming and the lack of a documented intent to develop the resources within a reasonable time frame. Other commercial considerations that may preclude the classification of contingent resources as reserves include factors such as legal, environmental, political and regulatory matters or a lack of markets.

The estimates of various classes of reserves (proved, probable, possible) and of contingent resources (low, best, high) in this news release represent arithmetic sums of multiple estimates of such classes for different properties, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of reserves and contingent resources and appreciate the differing probabilities of recovery associated with each class.

Encana uses the term resource play. Resource play is a term used by Encana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

The practice of preparing production and reserve quantities data under Canadian disclosure requirements (National Instrument 51-101) differs from the disclosure under U.S. protocols prepared in accordance with the requirements of the SEC. The primary differences between the two reporting requirements include:

a. the Canadian standards require disclosure of proved and probable reserves, while the U.S. standards require disclosure of only proved reserves;

b. the Canadian standards require the use of forecast prices in the estimation of reserves, while the U.S. standards require the use of 12-month average historical prices which are held constant;

c. the Canadian standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis, while the U.S standards require disclosure on a net (after royalties) basis;

d. the Canadian standards require disclosure of production on a gross (before royalties) basis, while the U.S. standards require disclosure on a net (after royalties) basis;

e. the Canadian standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. standards; and

f. the Canadian standards require that proved undeveloped reserves be reviewed annually for retention or reclassification if development has not proceeded as previously planned, while the U.S. standards specify a five year limit after initial booking for the development of proved undeveloped reserves.

30-day initial production and short-term rates are not necessarily indicative of long-term performance or of ultimate recovery.

In this news release, certain oil and NGLs volumes have been converted to cubic feet equivalent (cfe) on the basis of one barrel to six thousand cubic feet (Mcf). Cfe may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head. Given that the value ratio based on the current price of 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.

ADVISORY REGARDING FORWARD-LOOKING STATEMENTS - In the interests of providing Encana shareholders and potential investors with information regarding Encana, including management's assessment of Encana's and its subsidiaries' future plans and operations, certain statements contained in this news release are forward-looking statements or information within the meaning of applicable securities legislation, collectively referred to herein as "forward-looking statements." Forward-looking statements in this news release include, but are not limited to: achieving the Company’s focus of developing its strong portfolio of resource plays producing natural gas, oil and NGLs; the Company’s disciplined capital investment plan and the success thereof; the successful implementation of the Company’s new strategy; anticipated positioning to deliver on priorities and objectives in 2014; anticipated drilling and production and number of wells and the success thereof (including in the Duvernay, Montney, DJ Basin, San Juan Basin and Tuscaloosa Marine Shale areas); anticipated oil, natural gas and NGLs production in 2014 and beyond; expected accelerated development in certain of the high return assets; expected netbacks in 2014 and beyond; the Company’s plan to maximize profitability through focused capital allocation and operating excellence; maintaining a balanced portfolio; maintaining capital discipline; anticipated cost reductions and the ability to preserve balance sheet strength; the Company’s ability to capture new opportunities and its ability to fund the Company’s activities in its five core growth areas;

the Company's ability to generate funds to finance its operations and future growth; anticipated capital investment (including by product and plays); expected hedging activities; anticipated oil, natural gas and NGLs prices; anticipated dividends; potential future discounts to market price in connection with the Company's DRIP; the anticipated production from Deep Panuke; the success of implementing the resource play hub strategy across certain plays; plans for the Company to become a leading North American resource play company; estimated reserves and economic contingent resources, including estimates of PUDs, future development costs associated with PUDs and the expected period within which to convert PUDs to proved developed reserves; and the expectation of meeting the targets in the Company's 2014 corporate guidance.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of, and assumptions regarding natural gas and liquids prices, including substantial or extended decline of the same and their adverse effect on the company's operations and financial condition and the value and amount of its reserves; assumptions based upon the company's current guidance; fluctuations in currency and interest rates; risk that the company may not conclude divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; product supply and demand; market competition; risks inherent in the company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; marketing margins; potential disruption or unexpected technical difficulties in developing new facilities; unexpected cost increases or technical difficulties in constructing or modifying processing facilities.

Risks associated with technology; the company's ability to acquire or find additional reserves; hedging activities resulting in realized and unrealized losses; business interruption and casualty losses; risk of the company not operating all of its properties and assets; counterparty risk; risk of downgrade in credit rating and its adverse effects; liability for indemnification obligations to third parties; variability of dividends to be paid; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the company's ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the company operates; terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the company; risk arising from price basis differential; risk arising from inability to enter into attractive hedges to protect the company's capital program; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana. Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. In addition, assumptions relating to such forward-looking statements generally include Encana's current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this news release.

Assumptions with respect to forward-looking information regarding expanding Encana's oil and NGLs production and extraction volumes are based on existing expansion of natural gas processing facilities in areas where Encana operates and the continued expansion and development of oil and NGL production from existing properties within its asset portfolio.

Forward-looking information respecting anticipated 2014 cash flow for Encana is based upon, among other things, achieving average production for 2014 of between 2.6 Bcf/d and 2.8 Bcf/d of natural gas and 70,000 bbls/d to 75,000 bbls/d of liquids, commodity prices for natural gas and liquids based on NYMEX $3.75 per MMBtu and WTI of $95 per bbl, an estimated U.S./Canadian dollar foreign exchange rate of $0.95 and a weighted average number of outstanding shares for Encana of approximately 741 million.

Furthermore, the forward-looking statements contained in this news release are made as of the date hereof and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this news release are expressly qualified by this cautionary statement.

Further information on Encana Corporation is available on the company's website, www.encana.com, or by contacting:

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Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") for Encana Corporation ("Encana" or the "Company") should be read with the audited Consolidated Financial Statements for the year ended December 31, 2013 ("Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2012.

The Consolidated Financial Statements and comparative information have been prepared in accordance with United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") and in U.S. dollars, except where another currency has been indicated. Production volumes are presented on an after royalties basis consistent with U.S. oil and gas reporting standards and the disclosure of U.S. oil and gas companies. The term "liquids" is used to represent oil, natural gas liquids ("NGLs") and condensate. The term "liquids rich" is used to represent natural gas streams with associated liquids volumes. This document is dated February 20, 2014.

Certain measures in this document do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. Non-GAAP measures are commonly used in the oil and gas industry and by Encana to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include: Cash Flow; Operating Earnings; Revenues, Net of Royalties, Excluding Unrealized Hedging; Debt, including the current portion ("Debt"); Net Debt to Debt Adjusted Cash Flow; Debt to Debt Adjusted Cash Flow; Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA"); Debt to Adjusted EBITDA; and Debt to Adjusted Capitalization. Further information regarding these measures can be found in the Non-GAAP Measures section of this MD&A, including reconciliations of Cash from Operating Activities to Cash Flow and of Net Earnings to Operating Earnings.

The following volumetric measures may be abbreviated throughout this MD&A: thousand cubic feet ("Mcf"); million cubic feet ("MMcf") per day ("MMcf/d"); million cubic feet equivalent ("Mcfe"); billion cubic feet ("Bcf") per day ("Bcf/d"); billion cubic feet equivalent ("Bcfe"); trillion cubic feet ("Tcf"); barrel ("bbl"); thousand barrels ("Mbbls") per day ("Mbbls/d"); million barrels ("MMbbls"); million British thermal units ("MMBtu").

Readers should also read the Advisory section located at the end of this document, which provides information on Forward-Looking Statements, Oil and Gas Information and Currency and References to Encana.

Encana's Strategic Objectives

Encana is a leading North American energy producer that is focused on developing its strong portfolio of resource plays producing natural gas, oil and NGLs. Encana is committed to growing long-term shareholder value through a disciplined focus on generating profitable growth. The Company is pursuing the key business objectives of balancing its commodity mix, focusing capital investments in high return scalable projects, maintaining portfolio flexibility to respond to changing market conditions, maximizing profitability through operating efficiencies, reducing costs and preserving balance sheet strength.

Encana has a history of entering prospective plays early and leveraging technology to unlock resources and build the underlying productive capacity at a low cost. Encana continually strives to improve operating efficiencies, foster technological innovation and lower its cost structures, while reducing its environmental footprint through resource play optimization. The Company's resource play hub model, which utilizes highly integrated production facilities, is used to develop resources by drilling multiple wells from central pad sites. Ongoing cost reductions are achieved through repeatable operations, optimizing equipment and processes, by applying continuous improvement techniques.

Encana hedges a portion of its expected natural gas and oil production volumes. The Company's hedging program reduces volatility and helps sustain Cash Flow and netbacks during periods of lower prices. Further information on the Company's commodity price positions as at December 31, 2013 can be found in the Results Overview section of this MD&A and in Note 21 to the Consolidated Financial Statements.

Additional information on expected results can be found in Encana's 2014 Corporate Guidance on the Company's website www.encana.com.

Encana's Business

Encana's reportable segments are determined based on the Company's operations and geographic locations as follows:

- **Canadian Division** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within Canada.

- **USA Division** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within the U.S.

- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canadian and USA Divisions. Market optimization activities include third party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment. Market Optimization sells substantially all of the Company's upstream production to third party customers. Transactions between segments are based on market values and are eliminated on consolidation. Financial information is presented on an after eliminations basis within this MD&A.

Corporate and Other mainly includes unrealized gains or losses recorded on derivative financial instruments. Once the instruments are settled, the realized gains and losses are recorded in the reporting segment to which the derivative instrument relates.

In 2014, the Company does not anticipate any significant change in reportable segments as a result of the business strategy announced in November 2013.

Results Overview

Highlights

In the year ended December 31, 2013, Encana reported:

- Cash Flow of $2,581 million, Operating Earnings of $802 million and Net Earnings of $236 million.
- Average natural gas production volumes of 2,777 MMcf/d and average oil and NGL production volumes of 53.9 Mbbls/d.
- Realized financial commodity hedging gains of $544 million before tax.
- Average realized natural gas prices, including financial hedges, of $4.09 per Mcf. Average realized oil prices, including financial hedges, of $88.19 per bbl. Average realized NGL prices of $48.95 per bbl.
- Proceeds received from divestitures totaling $705 million before tax.
- Repayment of the 4.75 percent $500 million debt maturity from cash in October 2013.
- Dividends paid of $0.67 per share.
- Cash and cash equivalents of $2,566 million at year end.

Developments for the Company during the year ended December 31, 2013 included the following:

- Appointed Doug Suttles as Encana's President & Chief Executive Officer and Director of the Company in June 2013 and subsequently announced a realignment of the Company's business strategy and corporate organizational structure in November 2013 to be implemented in 2014.
- Announced plans to transfer Encana's royalty business, whose assets comprise fee simple mineral title and certain royalty interests in lands located predominantly in Alberta, into a separate company. Encana plans to subsequently divest a portion of its interest in the new company through an initial public offering ("IPO") in mid-2014. Encana intends to retain a majority stake in the new company. The transaction is subject to approval by Encana's Board of Directors, due diligence, favourable market conditions and stock exchange, regulatory and third party approvals.
- Commenced production at the Deep Panuke natural gas facility located offshore Nova Scotia in August 2013 and reached commercial operation with the issuance of the Production Acceptance Notice in December 2013.
- Completed the sale of the Company's 30 percent interest in the proposed Kitimat liquefied natural gas ("LNG") export terminal in British Columbia in February 2013.

Financial Results

($ millions, except per share)	2013 Annual	2013 Q4	2013 Q3	2013 Q2	2013 Q1	2012 Annual	2012 Q4	2012 Q3	2012 Q2	2012 Q1	2011 Annual
Cash Flow [(1)]	**$ 2,581**	**$ 677**	**$ 660**	**$ 665**	**$ 579**	$ 3,537	$ 809	$ 913	$ 794	$1,021	$ 4,216
per share - diluted	**3.50**	**0.91**	**0.89**	**0.90**	**0.79**	4.80	1.10	1.24	1.08	1.39	5.72
Operating Earnings [(1)]	**802**	**226**	**150**	**247**	**179**	997	296	263	198	240	1,191
per share - diluted	**1.09**	**0.31**	**0.20**	**0.34**	**0.24**	1.35	0.40	0.36	0.27	0.33	1.62
Net Earnings (Loss)	**236**	**(251)**	**188**	**730**	**(431)**	(2,794)	(80)	(1,244)	(1,482)	12	5
per share - basic and diluted	**0.32**	**(0.34)**	**0.25**	**0.99**	**(0.59)**	(3.79)	(0.11)	(1.69)	(2.01)	0.02	0.01
Production Volumes											
Natural Gas (MMcf/d)	**2,777**	**2,744**	**2,723**	**2,766**	**2,877**	2,981	2,948	2,905	2,802	3,272	3,333
Oil & NGLs (Mbbls/d)											
Oil	**25.8**	**33.0**	**27.2**	**22.9**	**20.0**	17.6	18.5	17.5	17.9	16.5	14.5
NGLs	**28.1**	**33.0**	**31.0**	**24.7**	**23.5**	13.4	17.7	12.8	10.3	12.8	9.5
Total Oil & NGLs	**53.9**	**66.0**	**58.2**	**47.6**	**43.5**	31.0	36.2	30.3	28.2	29.3	24.0
Capital Investment	**2,712**	**717**	**641**	**639**	**715**	3,476	780	779	797	1,120	4,610
Net Acquisitions & (Divestitures)	**(521)**	**(72)**	**(51)**	**(312)**	**(86)**	(3,664)	(1,327)	31	(8)	(2,360)	(1,565)
Revenues, Net of Royalties	**5,858**	**1,423**	**1,392**	**1,984**	**1,059**	5,160	1,605	1,025	731	1,799	8,467
Revenues, Net of Royalties, Excluding Unrealized Hedging [(1)]	**6,205**	**1,719**	**1,518**	**1,523**	**1,445**	6,601	1,723	1,623	1,526	1,729	7,613
Realized Hedging Gains, before tax	**544**	**174**	**175**	**52**	**143**	2,161	420	578	636	527	948
Ceiling Test Impairments, after tax	**-**	**-**	**-**	**-**	**-**	(3,179)	(291)	(1,193)	(1,695)	-	(1,687)
Total Assets	**17,648**					18,700					23,415
Total Debt	**7,124**					7,675					8,150
Cash & Cash Equivalents	**2,566**					3,179					800

(1) A non-GAAP measure, which is defined under the Non-GAAP Measures section of this MD&A.

Encana's quarterly net earnings can be significantly impacted by fluctuations in commodity prices, realized and unrealized hedging gains and losses, production volumes, foreign exchange rates and non-cash ceiling test impairments which are provided in the Financial Results table and Quarterly Prices and Foreign Exchange Rates table within this MD&A. Quarterly net earnings are also impacted by Encana's interim income tax expense calculated using the estimated annual effective income tax rate as discussed in the Critical Accounting Estimates section of this MD&A.

Q4 2013 versus Q4 2012

Cash Flow of $677 million decreased $132 million primarily due to lower realized financial hedging gains of $246 million before tax. In the three months ended December 31, 2013, Cash Flow was impacted by the following significant items:

- Realized financial hedging gains before tax were $174 million compared to $420 million in 2012.
- Average realized natural gas prices, excluding financial hedges, were $3.69 per Mcf compared to $3.45 per Mcf in 2012 reflecting higher benchmark prices. Average natural gas production volumes of 2,744 MMcf/d decreased 204 MMcf/d from 2,948 MMcf/d in 2012 primarily as a result of the Company's capital investment focus in oil and liquids rich natural gas plays, a reduced capital investment program, natural declines and divestitures, partially offset by successful drilling programs and production from the Deep Panuke offshore natural gas facility.

- Average oil and NGL production volumes of 66.0 Mbbls/d increased 29.8 Mbbls/d from 36.2 Mbbls/d in 2012 primarily due to successful drilling programs in oil and liquids rich natural gas plays and the extraction of additional liquids volumes processed through third party facilities. Higher oil and NGL volumes increased revenues by $190 million.
- Transportation and processing expense increased $87 million primarily due to costs related to higher production volumes processed through third party facilities and costs related to the Deep Panuke offshore natural gas facility.
- Administrative expense increased primarily due to restructuring charges as discussed in the Other Operating Results section of this MD&A.
- Current tax was a recovery of $25 million compared to an expense of $62 million in 2012.

Operating Earnings of $226 million decreased $70 million primarily due to the items discussed in the Cash Flow section. Operating Earnings excludes restructuring charges as described in the Non-GAAP Measures section of this MD&A.

Net Loss was $251 million compared to a Net Loss of $80 million in 2012. The Net Loss for the fourth quarter of 2013 was primarily due to the items discussed in the Cash Flow and Operating Earnings sections, partially offset by the inclusion of an after-tax non-cash ceiling test impairment of $291 million in the 2012 comparative. Net Loss for the fourth quarter of 2013 was also impacted by higher unrealized hedging losses of $137 million after tax, a higher after-tax non-operating foreign exchange loss, higher administrative expense as a result of restructuring charges and deferred tax expense.

2013 versus 2012

Cash Flow of $2,581 million decreased $956 million primarily due to lower realized financial hedging gains of $1,617 million before tax, partially offset by higher realized natural gas prices which increased revenues $790 million. In 2013, Cash Flow was impacted by the following significant items:

- Realized financial hedging gains before tax were $544 million compared to $2,161 million in 2012.
- Average realized natural gas prices, excluding financial hedges, were $3.57 per Mcf compared to $2.83 per Mcf in 2012 reflecting higher benchmark prices which increased revenues $790 million. Average natural gas production volumes of 2,777 MMcf/d decreased 204 MMcf/d from 2,981 MMcf/d in 2012 primarily as a result of the Company's capital investment focus in oil and liquids rich natural gas plays, a reduced capital investment program and natural declines, partially offset by shut-in production volumes in 2012, successful drilling programs and production from the Deep Panuke offshore natural gas facility in 2013. Lower natural gas volumes decreased revenues $208 million.
- Average realized liquids prices, excluding hedges, were $67.30 per bbl compared to $75.12 per bbl in 2012 which decreased revenues $168 million. Average oil and NGL production volumes of 53.9 Mbbls/d increased 22.9 Mbbls/d from 31.0 Mbbls/d in 2012 primarily due to successful drilling programs in oil and liquids rich natural gas plays, the extraction of additional liquids volumes processed through third party facilities and additional NGL volumes resulting from new and renegotiated gathering and processing agreements. Higher oil and NGL volumes increased revenues $640 million.
- Transportation and processing expense increased $245 million primarily due to costs related to higher production volumes processed through third party facilities, additional NGL volumes resulting from new and renegotiated gathering and processing agreements, costs related to the Deep Panuke offshore natural gas facility and higher firm processing costs.
- Operating expense increased $65 million primarily due to an increased focus on emerging oil and liquids rich natural gas plays.
- Administrative expense increased primarily due to restructuring charges as discussed in the Other Operating Results section of this MD&A.

Operating Earnings of $802 million decreased $195 million primarily due to the items discussed in the Cash Flow section, partially offset by lower depreciation, depletion and amortization ("DD&A") and lower deferred tax. Operating Earnings excludes restructuring charges as described in the Non-GAAP Measures section of this MD&A.

Net Earnings were $236 million compared to a Net Loss of $2,794 million in 2012 primarily due to the inclusion of after-tax non-cash ceiling test impairments of $3,179 million in the 2012 comparative, partially offset by the items discussed in the Cash Flow and Operating Earnings sections. Net Earnings for 2013 were also impacted by lower unrealized hedging losses of $770 million after tax, partially offset by an after-tax non-operating foreign exchange loss and higher administrative expense as a result of restructuring charges.

2012 versus 2011

Cash Flow of $3,537 million decreased $679 million primarily due to lower realized commodity prices which decreased revenues $1,564 million, partially offset by higher realized financial hedging gains of $1,213 million before tax. In 2012, Cash Flow was impacted by the following significant items:

- Realized financial hedging gains before tax were $2,161 million compared to $948 million in 2011.
- Average realized natural gas prices, excluding financial hedges, were $2.83 per Mcf compared to $4.17 per Mcf in 2011. Average natural gas production volumes of 2,981 MMcf/d decreased 352 MMcf/d from 3,333 MMcf/d in 2011 primarily as a result of shut-in and curtailed production and the Company's capital investment focus in oil and liquids rich natural gas plays.
- Average realized liquids prices, excluding financial hedges, were $75.12 per bbl compared to $85.36 per bbl in 2011. Average oil and NGL production volumes of 31.0 Mbbls/d increased 7.0 Mbbls/d from 24.0 Mbbls/d in 2011.

Operating Earnings of $997 million decreased $194 million primarily due to the items discussed in the Cash Flow section, partially offset by lower DD&A and lower deferred tax.

Net Loss was $2,794 million compared to Net Earnings of $5 million in 2011. The Net Loss for 2012 was primarily due to unrealized hedging losses, higher non-cash ceiling test impairments and the items discussed in the Cash Flow and Operating Earnings sections. The Net Loss for 2012 was partially offset by an unrealized foreign exchange gain on the revaluation of long-term debt and a deferred tax recovery.

The Company's after-tax non-cash ceiling test impairments of $3,179 million in 2012 and $1,687 million in 2011 primarily resulted from the decline in the 12-month average trailing natural gas prices. Under full cost accounting, the carrying amount of Encana's natural gas and oil properties within each country cost centre is subject to a ceiling test performed quarterly.

Quarterly Prices and Foreign Exchange Rates

	2013					2012					2011
(average for the period)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Encana Realized Pricing											
Including Hedging											
Natural Gas ($/Mcf)	**$ 4.09**	**$ 4.34**	**$ 4.00**	**$ 4.17**	**$ 3.86**	$ 4.82	$ 5.02	$ 4.91	$ 4.79	$ 4.58	$ 4.96
Oil ($/bbl)	**88.19**	**85.39**	**90.42**	**88.27**	**89.71**	84.06	79.75	80.04	84.62	92.65	86.70
NGLs ($/bbl) (1)	**48.95**	**48.59**	**46.35**	**49.63**	**52.24**	63.37	52.97	61.34	72.88	72.30	83.32
Total Oil & NGLs ($/bbl)	**67.75**	**67.01**	**66.95**	**68.25**	**69.45**	75.12	66.65	72.17	80.32	83.77	85.36
Excluding Hedging											
Natural Gas ($/Mcf)	**3.57**	**3.69**	**3.26**	**3.99**	**3.35**	2.83	3.45	2.77	2.25	2.80	4.17
Oil ($/bbl)	**87.25**	**82.54**	**96.09**	**85.89**	**84.46**	84.06	79.75	80.04	84.62	92.65	86.70
NGLs ($/bbl)	**48.95**	**48.59**	**46.35**	**49.63**	**52.24**	63.37	52.97	61.34	72.88	72.30	83.32
Total Oil & NGLs ($/bbl)	**67.30**	**65.58**	**69.60**	**67.10**	**67.04**	75.12	66.65	72.17	80.32	83.77	85.36
Natural Gas Price Benchmarks											
NYMEX ($/MMBtu)	**3.65**	**3.60**	**3.58**	**4.09**	**3.34**	2.79	3.40	2.81	2.22	2.74	4.04
AECO (C$/Mcf)	**3.16**	**3.15**	**2.82**	**3.59**	**3.08**	2.40	3.06	2.19	1.83	2.52	3.67
Rockies (Opal) ($/MMBtu)	**3.50**	**3.48**	**3.37**	**3.89**	**3.26**	2.63	3.26	2.56	2.01	2.67	3.80
HSC ($/MMBtu)	**3.63**	**3.57**	**3.55**	**4.11**	**3.30**	2.75	3.35	2.84	2.17	2.65	4.02
Basis Differential ($/MMBtu)											
AECO/NYMEX	**0.57**	**0.59**	**0.89**	**0.56**	**0.27**	0.38	0.32	0.62	0.39	0.22	0.31
Rockies/NYMEX	**0.15**	**0.12**	**0.21**	**0.20**	**0.08**	0.16	0.14	0.25	0.21	0.07	0.24
HSC/NYMEX	**0.02**	**0.03**	**0.03**	**(0.02)**	**0.04**	0.04	0.05	(0.03)	0.05	0.09	0.02
Oil Price Benchmarks											
West Texas Intermediate (WTI) ($/bbl)	**97.97**	**97.46**	**105.81**	**94.17**	**94.36**	94.21	88.22	92.20	93.35	103.03	95.11
Edmonton Light Sweet (C$/bbl)	**93.11**	**86.58**	**103.65**	**92.67**	**87.43**	87.02	83.99	84.33	83.95	92.23	95.03
Foreign Exchange											
U.S./Canadian Dollar Exchange Rate	**0.971**	**0.953**	**0.963**	**0.977**	**0.992**	1.000	1.009	1.005	0.990	0.999	1.012

(1) The Company did not settle any NGL hedges during the periods presented.

Encana's financial results are influenced by fluctuations in commodity prices, price differentials and the U.S./Canadian dollar exchange rate. In 2013, Encana's average realized natural gas price, excluding hedging, reflected higher benchmark prices compared to 2012. Hedging activities contributed an additional $0.52 per Mcf to the average realized natural gas price in 2013. Encana's average realized oil price, excluding hedging for 2013, reflected higher benchmark prices. Hedging activities contributed an additional $0.94 per bbl to the average realized oil price in 2013. The Company's 2013 NGLs price reflected a lower proportion of higher value condensate included in the total NGL product mix.

In 2012, Encana's average realized natural gas price, excluding hedging, reflected lower benchmark prices compared to 2011. Hedging activities contributed an additional $1.99 per Mcf to the average realized natural gas price in 2012. In 2012, Encana's average realized oil price reflected lower benchmark prices compared to 2011. The Company's 2012 NGLs price reflected a lower proportion of higher value condensate included in the total NGL product mix.

As a means of managing commodity price volatility and its impact on cash flows, Encana enters into various financial hedge agreements. Unsettled derivative financial contracts are recorded at the date of the financial statements based on the fair value of the contracts. Changes in fair value result from volatility in forward curves of commodity prices and changes in the balance of unsettled contracts between periods. The changes in fair value are recognized in revenue as unrealized hedging gains and losses. Realized hedging gains and losses are recognized in revenue when derivative financial contracts are settled.

At December 31, 2013, Encana has hedged approximately 2,138 MMcf/d of expected 2014 production at an average price of $4.17 per Mcf and approximately 825 MMcf/d of expected 2015 production at an average price of $4.37 per Mcf. In addition, Encana has hedged approximately 9.5 Mbbls/d of expected 2014 oil production using WTI fixed price contracts at an average price of $94.19 per bbl. The Company's hedging program helps sustain Cash Flow and netbacks during periods of lower prices. For additional information, see the Risk Management - Financial Risks section of this MD&A.

Reserves Quantities

Since its formation in 2002, Encana has retained independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of the Company's natural gas, oil and NGL reserves annually. The Company has a Reserves Committee composed of independent Board of Directors ("Board") members that reviews the qualifications and appointment of the IQREs. The Reserves Committee also reviews the procedures for providing information to the IQREs. All booked reserves are based upon annual evaluations by the IQREs.

As required by Canadian regulatory standards, Encana's disclosure of reserves data is in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Encana's 2013 Canadian protocol disclosure includes proved reserves quantities before and after royalties employing forecast prices and costs and is available in Encana's Annual Information Form ("AIF"). Canadian standards require reconciliations in this section to include cubic feet equivalent. The oil and NGL volumes have been converted to cubic feet equivalent on the basis of one Mbbls to six MMcf based on an energy equivalency conversion method primarily applicable at the burner tip. This energy equivalency conversion method does not represent value equivalency, as the current price of oil and NGLs compared to natural gas is significantly higher.

Supplementary oil and gas information, including proved reserves on an after royalties basis, is provided in accordance with U.S. disclosure requirements in Note 24 to the December 31, 2013 Consolidated Financial Statements. As Encana follows U.S. GAAP full cost accounting for oil and gas activities, the U.S. protocol reserves estimates are key inputs to the Company's depletion and ceiling test impairment calculations.

The Canadian standards require the use of forecast prices in the estimation of reserves and the disclosure of before and after royalties volumes. The U.S. standards require the use of 12-month average trailing prices in the estimation of reserves and the disclosure of after royalties volumes. The following sections provide Encana's Canadian protocol and U.S. protocol reserves quantities.

Canadian Protocol Reserves Quantities

Proved Reserves by Country
(Forecast Prices and Costs; Before Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
(as at December 31)	**2013**	2012	2011	**2013**	2012	2011
Canada	**5,031**	6,730	7,067	**141.1**	126.3	106.5
United States	**4,887**	6,660	8,432	**136.2**	156.2	47.3
Total	**9,918**	13,390	15,499	**277.3**	282.5	153.8

Proved Reserves Reconciliation
(Forecast Prices and Costs; Before Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)			
	Canada	United States	Total	Canada	United States	Total	**Total** (Bcfe)
December 31, 2012	6,730	6,660	13,390	126.3	156.2	282.5	15,085
Extensions	533	296	829	33.8	23.5	57.3	1,173
Discoveries	32	-	32	3.2	-	3.2	51
Technical revisions	(1,082)	(1,424)	(2,506)	(9.1)	(32.4)	(41.5)	(2,755)
Economic factors	(121)	(46)	(167)	(0.1)	(1.3)	(1.4)	(176)
Acquisitions	-	10	10	-	0.8	0.8	15
Dispositions	(514)	(2)	(516)	(3.2)	(0.1)	(3.3)	(535)
Production	(547)	(607)	(1,154)	(9.8)	(10.5)	(20.3)	(1,276)
December 31, 2013	5,031	4,887	9,918	141.1	136.2	277.3	11,582

Encana's 2013 proved natural gas reserves before royalties of approximately 9.9 Tcf decreased 3.5 Tcf from 2012 primarily due to changes in the Company's development plans and the resulting impact on proved undeveloped reserves bookings, which are included in technical revisions. Divestitures also reduced 2013 proved reserves. Extensions and discoveries of approximately 0.9 Tcf replaced 75 percent of production before royalties during the year.

Encana's 2013 proved oil and NGL reserves before royalties of approximately 277.3 MMbbls decreased 5.2 MMbbls from 2012 primarily due to technical revisions which were impacted by a decrease in NGL reserves in the U.S. resulting from ethane rejection. Ethane rejection occurs when ethane is not recovered from the production stream as NGLs and is sold as natural gas instead. Extensions and discoveries of approximately 60.5 MMbbls replaced 298 percent of production before royalties during the year.

Proved Reserves by Country
(Forecast Prices and Costs; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
(as at December 31)	**2013**	2012	2011	**2013**	2012	2011
Canada	**4,550**	6,207	6,607	**122.2**	113.1	94.4
United States	**4,026**	5,410	6,834	**112.7**	127.3	38.6
Total	**8,576**	11,617	13,441	**234.9**	240.4	133.0

Proved Reserves Reconciliation
(Forecast Prices and Costs; After Royalties)

	Natural Gas (Bcf)			**Oil & NGLs** (MMbbls)			
	Canada	United States	Total	Canada	United States	Total	**Total** (Bcfe)
December 31, 2012	6,207	5,410	11,617	113.1	127.3	240.4	13,059
Extensions and discoveries	508	264	772	30.3	19.4	49.7	1,070
Revisions (1)	(1,152)	(1,164)	(2,316)	(7.6)	(26.0)	(33.6)	(2,518)
Acquisitions	-	8	8	-	0.7	0.7	12
Dispositions	(490)	(1)	(491)	(2.5)	(0.1)	(2.6)	(506)
Production	(523)	(491)	(1,014)	(11.1)	(8.6)	(19.7)	(1,132)
December 31, 2013	4,550	4,026	8,576	122.2	112.7	234.9	9,985

(1) Includes economic factors.

Encana's 2013 proved natural gas reserves after royalties of approximately 8.6 Tcf decreased 3.0 Tcf from 2012 primarily due to changes in the Company's development plans and the resulting impact on proved undeveloped reserves bookings which are included in revisions. Divestitures also reduced 2013 proved reserves. Extensions and discoveries of approximately 0.8 Tcf replaced 76 percent of production after royalties during the year.

Encana's 2013 proved oil and NGL reserves after royalties of approximately 234.9 MMbbls decreased 5.5 MMbbls from 2012 primarily due to revisions which were impacted by a decrease in NGL reserves in the U.S. resulting from ethane rejection. Extensions and discoveries of approximately 49.7 MMbbls replaced 252 percent of production after royalties during the year.

Forecast Prices

The reference prices below were utilized in the determination of reserves.

	Natural Gas		**Oil & NGLs**	
	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)	WTI ($/bbl)	Edmonton Light Sweet (C$/bbl)
2011 Price Assumptions				
2012	3.80	3.49	97.00	97.96
2013 - 2021	4.50 - 7.17	4.13 - 6.58	100.00 - 107.56	101.02 - 108.73
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr
2012 Price Assumptions				
2013	3.75	3.38	90.00	85.00
2014 - 2022	4.25 - 6.27	3.83 - 5.64	92.50 - 104.57	91.50 - 103.57
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr
2013 Price Assumptions				
2014	4.25	4.03	97.50	92.76
2015 - 2023	4.50 - 5.97	4.26 - 5.66	97.50 - 104.57	97.37 - 106.93
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr

U.S. Protocol Reserves Quantities

Proved Reserves by Country
(12-month average trailing prices; After Royalties)

(as at December 31)	Natural Gas (Bcf) 2013	2012	2011	Oil & NGLs (MMbbls) 2013	2012	2011
Canada	**3,975**	4,550	6,329	**110.2**	101.6	95.0
United States	**3,877**	4,242	6,511	**110.6**	108.4	38.2
Total	**7,852**	8,792	12,840	**220.8**	210.0	133.2

Proved Reserves Reconciliation
(12-month average trailing prices; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
	Canada	United States	Total	Canada	United States	Total
December 31, 2012	4,550	4,242	8,792	101.6	108.4	210.0
Revisions and improved recovery	(256)	(362)	(618)	(7.0)	(17.3)	(24.3)
Extensions and discoveries	499	482	981	28.2	27.6	55.8
Purchase of reserves in place	-	7	7	-	0.6	0.6
Sale of reserves in place	(295)	(1)	(296)	(1.5)	(0.1)	(1.6)
Production	(523)	(491)	(1,014)	(11.1)	(8.6)	(19.7)
December 31, 2013	3,975	3,877	7,852	110.2	110.6	220.8

Encana's 2013 proved natural gas reserves after royalties of approximately 7.9 Tcf decreased 0.9 Tcf from 2012. Revisions and improved recovery included a reduction of approximately 2.9 Tcf due to lower proved undeveloped reserves bookings resulting from changes in the Company's development plans, partially offset by additions of approximately 2.2 Tcf due to higher 12-month average trailing prices and minor positive revisions. Divestitures also reduced 2013 proved reserves. Extensions and discoveries of approximately 1.0 Tcf replaced 97 percent of production during the year.

Encana's 2013 proved oil and NGL reserves after royalties of approximately 220.8 MMbbls increased 10.8 MMbbls from 2012 primarily due to extensions and discoveries. Revisions and improved recovery was impacted by a decrease in NGL reserves primarily due to ethane rejection in the U.S. Extensions and discoveries of approximately 55.8 MMbbls replaced 283 percent of production during the year.

12-Month Average Trailing Prices

The reference prices below were utilized in the determination of reserves. The 12-month average trailing price is calculated as the average of the prices on the first day of each month within the trailing 12-month period.

	Natural Gas		Oil & NGLs	
	Henry Hub ($/MMBtu)	AECO (C$/MMBtu)	WTI ($/bbl)	Edmonton Light Sweet (C$/bbl)
Reserves Pricing (1)				
2011	4.12	3.76	96.19	96.53
2012	2.76	2.35	94.71	87.42
2013	3.67	3.14	96.94	93.44

(1) All prices were held constant in all future years when estimating reserves.

Production and Net Capital Investment

Production Volumes (After Royalties)

(average daily)	**2013**	2012	2011
Natural Gas (MMcf/d)			
Canadian Division	**1,432**	1,359	1,454
USA Division	**1,345**	1,622	1,879
	2,777	2,981	3,333
Oil (Mbbls/d)			
Canadian Division	**11.9**	7.3	5.1
USA Division	**13.9**	10.3	9.4
	25.8	17.6	14.5
NGLs (Mbbls/d)			
Canadian Division	**18.5**	12.1	9.4
USA Division	**9.6**	1.3	0.1
	28.1	13.4	9.5
Total Oil & NGLs (Mbbls/d)			
Canadian Division	**30.4**	19.4	14.5
USA Division	**23.5**	11.6	9.5
	53.9	31.0	24.0

2013 versus 2012

Average natural gas production volumes for 2013 compared to 2012 were impacted by the Company's capital investment focus in oil and liquids rich natural gas plays, a reduced capital investment program and natural declines, partially offset by shut-in production volumes in 2012. In 2013, average natural gas production volumes of 2,777 MMcf/d decreased 204 MMcf/d from 2012. The Canadian Division volumes were higher primarily due to successful drilling programs, mainly at Cutbank Ridge, production from the Deep Panuke offshore natural gas facility, and shut-in production volumes in 2012, partially offset by natural declines and the sale of the Jean Marie natural gas assets in Greater Sierra. The USA Division volumes were lower primarily due to natural declines, partially offset by shut-in production volumes in 2012.

In 2013, average oil and NGL production volumes of 53.9 Mbbls/d increased 22.9 Mbbls/d from 2012. The Canadian Division volumes were higher primarily due to the extraction of additional liquids volumes at the Musreau plant in Bighorn and the Gordondale plant in Peace River Arch and successful drilling programs in Peace River Arch and Clearwater. The USA Division volumes were higher primarily due to successful drilling programs in oil and liquids rich natural gas plays and new and renegotiated gathering and processing agreements which resulted in additional NGL volumes primarily in Piceance and Jonah.

2012 versus 2011

In 2012, average natural gas production volumes of 2,981 MMcf/d decreased 352 MMcf/d from 2011. The Canadian Division volumes were lower primarily due to shut-in production and divestitures, partially offset by a successful drilling program at Cutbank Ridge and Bighorn. The USA Division volumes were lower primarily due to natural declines, divestitures in Texas and shut-in production, partially offset by a successful drilling program in Piceance. During 2012, Encana announced plans to shut in and curtail natural gas production volumes of approximately 250 MMcf/d in areas subject to higher decline and higher variable costs. The shut-in volumes were brought back on prior to year end.

In 2012, average oil and NGL production volumes of 31.0 Mbbls/d increased 7.0 Mbbls/d from 2011. The Canadian Division volumes were higher primarily due to the extraction of additional liquids volumes at the Musreau plant in Bighorn, higher royalty interest volumes and successful drilling programs in Peace River Arch and Bighorn. The USA Division volumes were higher primarily due to successful drilling programs in oil and liquids rich natural gas plays and renegotiated gathering and processing agreements which resulted in additional NGL volumes.

Net Capital Investment

($ millions)		**2013**		2012		2011
Canadian Division	**$**	**1,365**	$	1,567	$	2,031
USA Division		**1,283**		1,727		2,446
Market Optimization		**3**		7		2
Corporate & Other		**61**		175		131
Capital Investment		**2,712**		3,476		4,610
Acquisitions		**184**		379		515
Divestitures		**(705)**		(4,043)		(2,080)
Net Acquisitions & (Divestitures)		**(521)**		(3,664)		(1,565)
Net Capital Investment	**$**	**2,191**	$	(188)	$	3,045

2013

Capital investment during 2013 was $2,712 million and reflected the Company’s disciplined capital spending which focused on investment in Encana’s highest return resource plays, investments in opportunities where development has demonstrated success and executing drilling programs with joint venture partners. Development of resource plays continued in Peace River Arch, Bighorn, Piceance and Haynesville. Investment in prospective oil and liquids rich natural gas plays was focused on the Duvernay, the San Juan Basin and the DJ Basin. In 2014, Encana will realign its capital investment program in support of the Company’s strategy announced in November 2013.

Acquisitions in 2013 were $28 million in the Canadian Division and $156 million in the USA Division, which primarily included land and property purchases with oil and liquids rich natural gas production potential.

Divestitures in 2013 were $685 million in the Canadian Division and $18 million in the USA Division. The Canadian Division included the sale of the Company’s Jean Marie natural gas assets in the Greater Sierra resource play in northeast British Columbia and other assets.

Encana is currently involved in a number of joint ventures with counterparties in both Canada and the U.S. Sharing development costs with third parties enables Encana to advance project development while reducing capital investment, thereby improving project returns.

2012

Capital investment during 2012 was $3,476 million and focused on completing previously initiated drilling programs, executing drilling programs with joint venture partners and increasing investment in oil and liquids rich natural gas development and exploration opportunities. Development of resource plays continued in Piceance, Haynesville, Bighorn, Cutbank Ridge and Peace River Arch and investment in prospective oil and liquids rich natural gas plays including the Duvernay, Clearwater Oil, the Tuscaloosa Marine Shale, Eaglebine, the Mississippian Lime, the DJ Niobrara and the San Juan Basin.

Acquisitions in 2012 were $139 million in the Canadian Division and $240 million in the USA Division and primarily included land and property purchases with oil and liquids rich natural gas production potential.

Divestitures in 2012 were $3,770 million in the Canadian Division and $271 million in the USA Division. The Canadian Division included C$1.45 billion received from a Mitsubishi Corporation subsidiary, C$1.18 billion received from a PetroChina Company Limited subsidiary, C$100 million received from a Toyota Tsusho Corporation subsidiary and approximately C$920 million received from the sale of two natural gas processing plants. The USA Division received the remaining proceeds of $114 million from the divestiture of the North Texas natural gas assets, with the majority of the proceeds received in December 2011.

2011

Capital investment during 2011 was $4,610 million and focused on continued development of Encana's resource plays, including Bighorn, Cutbank Ridge, Haynesville and Piceance.

Acquisitions in 2011 were $410 million in the Canadian Division and $105 million in the USA Division, which included land and property purchases that were complementary to existing Company assets and focused on acreage with oil and liquids rich natural gas production potential.

Divestitures in 2011 were $350 million in the Canadian Division and $1,730 million in the USA Division. The USA Division divestitures included the sales of the Fort Lupton natural gas processing plant for proceeds of $296 million, the South Piceance natural gas gathering assets for proceeds of $547 million and the majority of the North Texas natural gas assets for proceeds of $836 million. Cash taxes increased by $114 million as a result of the sale of the South Piceance assets and the North Texas assets. Divestiture amounts were net of amounts recovered for capital expenditures incurred prior to the sale of certain natural gas gathering and processing assets.

Amounts received from the divestiture transactions above have been deducted from the respective Canadian and U.S. full cost pools.

Divisional Results

Canadian Division

Operating Cash Flow

	Operating Cash Flow ($ millions)			Natural Gas Netback ($/Mcf)			Oil & NGLs Netback ($/bbl)		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues, Net of Royalties, excluding Hedging	**$ 2,548**	$ 1,802	$ 2,507	**$ 3.35**	$ 2.58	$ 3.79	**$ 65.06**	$ 70.84	$ 85.41
Realized Financial Hedging Gain	**276**	958	365	**0.51**	1.97	0.69	**0.46**	-	-
Expenses									
Production and mineral taxes	**15**	9	15	**0.01**	-	0.02	**0.96**	1.13	0.90
Transportation and processing	**756**	555	490	**1.37**	1.12	0.91	**2.89**	0.75	1.45
Operating	**372**	352	380	**0.61**	0.67	0.68	**3.56**	2.09	1.23
Operating Cash Flow/Netback	**$ 1,681**	$ 1,844	$ 1,987	**$ 1.87**	$ 2.76	$ 2.87	**$ 58.11**	$ 66.87	$ 81.83

	Natural Gas (MMcf/d)			Oil & NGLs (Mbbls/d)		
	2013	2012	2011	**2013**	2012	2011
Production Volumes - After Royalties	**1,432**	1,359	1,454	**30.4**	19.4	14.5

2013 versus 2012

Operating Cash Flow of $1,681 million decreased $163 million primarily due to lower realized financial hedging gains of $682 million, partially offset by higher realized natural gas prices which increased revenues $405 million. In 2013, Cash Flow was impacted by the following significant items:

- Realized financial hedging gains were $276 million compared to $958 million in 2012.
- Higher natural gas prices reflected higher benchmark prices, which increased revenues by $405 million. Average natural gas production volumes of 1,432 MMcf/d were higher by 73 MMcf/d, which increased revenues by $103 million. This was primarily due to successful drilling programs, mainly at Cutbank Ridge, shut-in production volumes in 2012 and production from the Deep Panuke offshore natural gas facility, partially offset by natural declines and the sale of the Jean Marie natural gas assets in Greater Sierra.
- Average oil and NGL production volumes of 30.4 Mbbls/d were higher by 11.0 Mbbls/d. This increased revenues by $281 million primarily due to the extraction of additional liquids volumes at the Musreau plant in Bighorn and the Gordondale plant in Peace River Arch and successful drilling programs in Peace River Arch and Clearwater. Lower liquids prices decreased revenues by $63 million.
- Transportation and processing expense increased $201 million primarily due to costs related to higher production volumes processed through third party facilities in Bighorn, Cutbank Ridge and Peace River Arch, costs related to the Deep Panuke offshore natural gas facility and higher firm processing costs.

2012 versus 2011

Operating Cash Flow of $1,844 million decreased $143 million primarily due to lower realized commodity prices which decreased revenues $695 million, partially offset by higher realized financial hedging gains of $593 million. In 2012, Cash Flow was impacted by the following significant items:

- Realized financial hedging gains were $958 million compared to $365 million in 2011.
- Lower natural gas prices reflected lower benchmark prices, which decreased revenues by $586 million. Average natural gas production volumes of 1,359 MMcf/d were lower by 95 MMcf/d. This decreased revenues by $158 million primarily due to shut-in and curtailed production and divestitures, partially offset

by a successful drilling program at Cutbank Ridge and Bighorn. A portion of 2012 production was shut in at Cutbank Ridge, Greater Sierra and Clearwater.

- Average oil and NGL production volumes of 19.4 Mbbls/d were higher by 4.9 Mbbls/d, which increased revenues by $156 million primarily due to the extraction of additional liquids volumes at the Musreau plant in Bighorn, higher royalty interest volumes and a successful drilling program in Peace River Arch and Bighorn. Lower liquids prices decreased revenues by $109 million.
- Transportation and processing expense increased $65 million primarily due to higher volumes processed through third party facilities, mainly resulting from the sale of two natural gas processing plants.

Results by Resource Play

	Natural Gas Production (MMcf/d)			Oil & NGLs Production (Mbbls/d)			Capital ($ millions)		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Cutbank Ridge	**506**	433	428	**1.8**	1.5	1.1	**$ 143**	$ 228	$ 371
Bighorn	**255**	242	230	**8.9**	5.8	3.5	**268**	333	397
Peace River Arch	**133**	108	101	**8.7**	2.9	2.1	**435**	220	156
Clearwater	**335**	374	433	**9.9**	8.6	7.0	**128**	131	354
Greater Sierra	**156**	200	260	**0.3**	0.5	0.8	**17**	118	325
Other and emerging	**47**	2	2	**0.8**	0.1	-	**374**	537	428
Total Canadian Division	**1,432**	1,359	1,454	**30.4**	19.4	14.5	**$ 1,365**	$ 1,567	$ 2,031

Other and emerging resource plays primarily includes results from the Duvernay prospective oil and liquids rich natural gas play and the Deep Panuke offshore natural gas facility. Production from the Deep Panuke offshore natural gas facility increased natural gas volumes by approximately 41 MMcf/d for 2013.

Greater Sierra average natural gas production volumes were lower in 2013 compared to 2012 primarily as a result of the sale of the Jean Marie natural gas assets which closed in the second quarter of 2013. Cutbank Ridge average natural gas production volumes have increased and capital investment has decreased during the periods presented as a result of partnership activity in the resource play.

Average oil and NGL production volumes during 2013 increased primarily due to the extraction of additional liquids volumes at the Musreau plant in Bighorn and the Gordondale plant in Peace River Arch and successful drilling programs in Peace River Arch and Clearwater.

Other Divisional Expenses

($ millions)	**2013**	2012	2011
Depreciation, depletion and amortization	**$ 601**	$ 748	$ 966
Impairments	**-**	1,822	2,249

In 2013, DD&A decreased from 2012 due to a lower depletion rate of $1.01 per Mcfe in 2013 compared to $1.41 per Mcfe in 2012, partially offset by higher production volumes in 2013. The lower depletion rate primarily resulted from ceiling test impairments recognized in 2012 and deductions from the full cost pool for amounts received from divestitures during 2012 and 2013.

In 2012, the Division recognized non-cash ceiling test impairments before tax of $1,822 million (2011 - $2,249 million). The impairments primarily resulted from the decline in the 12-month average trailing natural gas prices, which reduced the Division’s proved reserves volumes and values as calculated under Securities and Exchange Commission (“SEC”) requirements.

USA Division

Operating Cash Flow

	Operating Cash Flow ($ millions)			Natural Gas Netback ($/Mcf)			Oil & NGLs Netback ($/bbl)		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues, Net of Royalties, excluding Hedging	**$ 2,499**	$ 2,170	$ 3,424	**$ 3.81**	$ 3.03	$ 4.47	**$ 70.18**	$ 82.33	$ 85.28
Realized Financial Hedging Gain	**264**	1,195	598	**0.53**	2.01	0.87	**0.44**	-	-
Expenses									
Production and mineral taxes	**119**	96	183	**0.16**	0.11	0.23	**4.79**	6.63	7.54
Transportation and processing	**722**	652	728	**1.47**	1.10	1.06	**-**	0.06	0.08
Operating	**411**	377	444	**0.69**	0.59	0.62	**7.02**	5.88	0.70
Operating Cash Flow/Netback	**$ 1,511**	$ 2,240	$ 2,667	**$ 2.02**	$ 3.24	$ 3.43	**$ 58.81**	$ 69.76	$ 76.96

	Natural Gas (MMcf/d)			Oil & NGLs (Mbbls/d)		
	2013	2012	2011	**2013**	2012	2011
Production Volumes - After Royalties	**1,345**	1,622	1,879	**23.5**	11.6	9.5

2013 versus 2012

Operating Cash Flow of $1,511 million decreased $729 million primarily due to lower realized financial hedging gains of $931 million, partially offset by higher realized natural gas prices which increased revenues $385 million. In 2013, Cash Flow was impacted by the following significant items:

- Realized financial hedging gains were $264 million compared to $1,195 million in 2012.
- Higher natural gas prices reflected higher benchmark prices, which increased revenues by $385 million. Average natural gas production volumes of 1,345 MMcf/d were lower by 277 MMcf/d. This decreased revenues by $311 million primarily due to natural declines, partially offset by shut-in production volumes in 2012.
- Average oil and NGL production volumes of 23.5 Mbbls/d were higher by 11.9 Mbbls/d. This increased revenues by $359 million primarily due to successful drilling programs in oil and liquids rich natural gas plays and new and renegotiated gathering and processing agreements which resulted in additional NGL volumes primarily in Piceance and Jonah. Lower liquids prices decreased revenues by $105 million.
- Transportation and processing expense increased $70 million primarily due to costs related to new and renegotiated gathering and processing agreements.
- Operating expense increased $34 million primarily due to an increased focus on emerging oil and liquids rich natural gas plays.

2012 versus 2011

Operating Cash Flow of $2,240 million decreased $427 million primarily due to lower realized natural gas prices which decreased revenues $856 million, partially offset by higher realized financial hedging gains of $597 million. In 2012, Cash Flow was impacted by the following significant items:

- Realized financial hedging gains were $1,195 million compared to $598 million in 2011.
- Lower natural gas prices reflected lower benchmark prices, which decreased revenues by $856 million. Average natural gas production volumes of 1,622 MMcf/d were lower by 257 MMcf/d. This decreased revenues by $412 million primarily due to natural declines, divestitures in Texas and shut-in production in Haynesville, partially offset by a successful drilling program in Piceance.

- Average oil and NGL production volumes of 11.6 Mbbls/d were higher by 2.1 Mbbls/d. This increased revenues by $66 million primarily due to successful drilling programs in oil and liquids rich natural gas plays and renegotiated gathering and processing agreements, which resulted in additional NGL volumes.
- Production and mineral taxes decreased $87 million primarily due to lower natural gas prices.
- Transportation and processing expense decreased $76 million primarily due to lower natural gas production volumes.
- Operating expense decreased $67 million primarily due to lower property taxes and the North Texas asset divestiture.

Results by Resource Play

	Natural Gas Production (MMcf/d)			**Oil & NGLs Production** (Mbbls/d)			**Capital** ($ millions)		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Piceance	**455**	475	435	**5.1**	2.2	1.9	**$ 241**	$ 328	$ 453
Jonah	**323**	411	471	**4.7**	4.1	4.3	**48**	102	275
Haynesville	**348**	475	508	**-**	-	-	**210**	337	1,018
Texas	**136**	167	376	**-**	0.1	0.3	**23**	62	310
Other and emerging	**83**	94	89	**13.7**	5.2	3.0	**761**	898	390
Total USA Division	**1,345**	1,622	1,879	**23.5**	11.6	9.5	**$ 1,283**	$ 1,727	$ 2,446

Other and emerging resource plays include results from prospective oil and liquids rich natural gas plays including the San Juan Basin, the DJ Basin, the Tuscaloosa Marine Shale and Eaglebine.

Average oil and NGL production volumes during 2013 increased primarily due to successful drilling programs in the DJ Basin, Piceance and the San Juan Basin and new and renegotiated gathering and processing agreements which resulted in additional NGL volumes primarily in Piceance and Jonah.

Average natural gas production volumes during 2013 in Jonah and Haynesville were impacted by natural declines and a reduced capital investment program.

Other Divisional Expenses

($ millions)	**2013**	2012	2011
Depreciation, depletion and amortization	**$ 818**	$ 1,102	$ 1,226
Impairments	**-**	2,842	-

In 2013, DD&A decreased from 2012 due to a lower depletion rate of $1.51 per Mcfe in 2013 compared to $1.78 per Mcfe in 2012 and lower production volumes in 2013. The lower depletion rate primarily resulted from ceiling test impairments recognized during 2012.

In 2012, the Division recognized non-cash ceiling test impairments before tax of $2,842 million (2011 - nil). The impairments primarily resulted from the decline in the 12-month average trailing natural gas prices, which reduced the Division’s proved reserves volumes and values as calculated under SEC requirements.

Market Optimization

($ millions)		2013		2012		2011
Revenues	**$**	**512**	$	419	$	703
Expenses						
Operating		**38**		48		40
Purchased product		**441**		349		635
Depreciation, depletion and amortization		**12**		12		12
	$	**21**	$	10	$	16

Market Optimization revenues and purchased product expense relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. Revenues and purchased product expense increased in 2013 compared to 2012 primarily due to higher commodity prices partially offset by lower volumes required for optimization. Revenues and purchased product expense decreased in 2012 compared to 2011 primarily due to lower commodity prices and lower volumes required for optimization.

Corporate and Other

($ millions)		2013		2012		2011
Revenues	**$**	**(241)**	$	(1,384)	$	870
Expenses						
Transportation and processing		**(2)**		24		(25)
Operating		**38**		17		2
Depreciation, depletion and amortization		**134**		94		78
Impairments		**21**		31		-
	$	**(432)**	$	(1,550)	$	815

Revenues mainly include unrealized hedging gains or losses recorded on derivative financial contracts which result from the volatility in forward curves of commodity prices and changes in the balance of unsettled contracts between periods. Transportation and processing expense reflects unrealized financial hedging gains or losses related to the Company's power financial derivative contracts. DD&A includes amortization of corporate assets, such as computer equipment, office buildings, furniture and leasehold improvements. Impairments relates to certain corporate assets.

Corporate and Other results include revenues and operating expenses related to the sublease of office space in The Bow office building. For further information on The Bow office sublease, refer to the Contractual Obligations and Contingencies section of this MD&A.

Other Operating Results

Expenses

($ millions)	2013	2012	2011
Accretion of asset retirement obligation	$ 53	$ 53	$ 50
Administrative	439	392	350
Interest	563	522	468
Foreign exchange (gain) loss, net	325	(107)	133
Other	(6)	1	21
	$ 1,374	$ 861	$ 1,022

Administrative expense in 2013 increased from 2012 primarily due to restructuring charges of approximately $88 million resulting from workforce reductions to align the organizational structure in support of the strategy announced in November 2013, partially offset by higher legal costs in 2012. Administrative expense in 2012 increased from 2011 primarily due to higher long-term compensation cost accruals and higher legal costs.

Interest expense in 2013 increased from 2012 primarily due to interest related to The Bow office building. Interest expense in 2012 increased from 2011 due to higher standby fees on available committed revolving bank credit facilities, a lower recovery of interest accrued on unrecognized tax benefits and interest related to The Bow office building. The Bow office obligation is discussed further in the Contractual Obligations and Contingencies section of this MD&A.

Foreign exchange gains and losses result from the impact of the fluctuations in the Canadian to U.S. dollar exchange rate. Foreign exchange gains and losses primarily arise from the revaluation and settlement of U.S. dollar long-term debt issued from Canada and the revaluation of other monetary assets and liabilities.

Income Tax

($ millions)	2013	2012	2011
Current Income Tax	$ (191)	$ (200)	$ (195)
Deferred Income Tax	(57)	(1,837)	212
Income Tax Expense (Recovery)	$ (248)	$ (2,037)	$ 17

Current income tax in 2013 was a recovery of $191 million primarily due to amounts in respect of prior periods. The current income tax recoveries of $200 million in 2012 and $195 million in 2011 were primarily due to the carry back of tax losses to prior years.

Total income tax was a recovery of $248 million in 2013 and decreased $1,789 million primarily due to higher net earnings before tax resulting from the non-cash ceiling test impairments included in 2012 results. In 2012, total income tax was a recovery of $2,037 million compared to an expense of $17 million in 2011 due to lower net earnings before tax primarily resulting from higher non-cash ceiling test impairments, lower commodity prices and unrealized hedging losses. The Net Earnings variances are further discussed in the Financial Results section of this MD&A.

Encana’s annual effective tax rate is impacted by earnings, statutory rate and other foreign differences, the effect of legislative changes, non-taxable capital gains and losses, tax differences on divestitures and transactions and partnership tax allocations in excess of funding.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As a result, there are tax matters under review. The Company believes that the provision for taxes is adequate.

Liquidity and Capital Resources

($ millions)		2013		2012		2011
Net Cash From (Used In)						
Operating activities	$	2,289	$	3,107	$	3,927
Investing activities		(1,895)		361		(3,631)
Financing activities		(909)		(1,111)		(194)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency		(98)		22		(1)
Increase (Decrease) in Cash and Cash Equivalents	$	(613)	$	2,379	$	101
Cash and Cash Equivalents, End of Year	$	2,566	$	3,179	$	800

Operating Activities

Net cash from operating activities in 2013 of $2,289 million decreased $818 million from 2012. Net cash from operating activities in 2012 of $3,107 million decreased $820 million from 2011. These decreases are primarily a result of the Cash Flow variances discussed in the Financial Results section of this MD&A. In 2013, the net change in non-cash working capital was a deficit of $179 million compared to a deficit of $323 million in 2012 and a deficit of $15 million in 2011.

The Company had a working capital surplus of $1,338 million at December 31, 2013 compared to $2,865 million at December 31, 2012. The decrease in working capital is primarily due to an increase in the current portion of long-term debt, a decrease in risk management assets and a decrease in accounts receivable and accrued revenues. At December 31, 2013, working capital included cash and cash equivalents of $2,566 million compared to $3,179 million at December 31, 2012. Encana expects that it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used in investing activities in 2013 was $1,895 million compared to net cash from investing activities of $361 million in 2012. The net cash used in investing activities primarily resulted from lower divestiture proceeds, partially offset by lower capital expenditures. Net cash from investing activities in 2012 was $361 million compared to net cash used in investing activities of $3,631 million in 2011. The net cash from investing activities primarily resulted from higher divestiture proceeds and lower capital expenditures. Reasons for these changes are discussed further in the Net Capital Investment section of this MD&A.

Investing activities in 2013 also included proceeds received from the sale of the Company’s 30 percent interest in the proposed Kitimat LNG export terminal in British Columbia which closed in February 2013.

Net cash used in investing activities in 2013 also included cash in reserve released from escrow of $44 million compared to $415 million in 2012. Net cash from investing activities in 2011 included cash placed in escrow of $383 million. Cash in reserve includes monies which are not available for general operating use, are segregated or held in escrow and include amounts received from counterparties related to jointly developed assets. At December 31, 2011, the Company also had amounts placed in escrow for a possible qualifying like-kind exchange for U.S. income tax purposes.

Financing Activities

Long-Term Debt

Encana's long-term debt, excluding the current portion, totaled $6,124 million at December 31, 2013 and $7,175 million at December 31, 2012. The current portion of long-term debt outstanding was $1,000 million at December 31, 2013 compared to $500 million at December 31, 2012. On October 15, 2013, the Company repaid its 4.75 percent $500 million debt maturity from cash. The Company expects that the remaining $1,000 million 5.80 percent notes which are due to mature on May 1, 2014 will be paid in cash. There were no outstanding balances under the Company's revolving credit facilities at December 31, 2013 or December 31, 2012.

Encana has the flexibility to refinance maturing long-term debt or repay debt maturities from existing sources of liquidity. Encana's primary sources of liquidity include cash and cash equivalents, revolving bank credit facilities, working capital, operating cash flow and proceeds from asset divestitures.

Credit Facilities and Shelf Prospectuses

Encana maintains two committed revolving bank credit facilities and a U.S. dollar shelf prospectus. In June 2013, the Company extended the maturity date of its existing revolving bank credit facilities to June 2018 and reduced the Canadian facility from C$4.0 billion to C$3.5 billion. As at December 31, 2013, Encana had available unused committed revolving bank credit facilities of $4.3 billion and unused capacity under a shelf prospectus for up to $4.0 billion.

- Encana has in place a revolving bank credit facility for C$3.5 billion ($3.3 billion) that remains committed through June 2018, all of which remained unused.
- One of Encana's U.S. subsidiaries has in place a revolving bank credit facility for $1.0 billion that remains committed through June 2018, of which $999 million remained unused.
- Encana has in place a shelf prospectus whereby it may issue from time to time up to $4.0 billion, or the equivalent in foreign currencies, of debt securities in the U.S. At December 31, 2013, the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions. The shelf prospectus expires in June 2014.

Encana had in place an unutilized shelf prospectus for up to C$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada which expired in June 2013. Encana did not renew the shelf prospectus as the Company had sufficient cash balances on hand and does not believe that access to the debt capital market in Canada will be required in the near term.

Encana is currently in compliance with, and expects that it will continue to be in compliance with, all financial covenants under its credit facility agreements. Management monitors Debt to Adjusted Capitalization as a proxy for Encana's financial covenant under its credit facility agreements which require debt to adjusted capitalization to be less than 60 percent. The definitions used in the covenant under the credit facilities adjust capitalization for cumulative historical ceiling test impairments that were recorded as at December 31, 2011 in conjunction with the Company's January 1, 2012 adoption of U.S. GAAP. Debt to Adjusted Capitalization was 36 percent at December 31, 2013 and 37 percent at December 31, 2012.

Outstanding Share Data

As at December 31, 2013 and February 18, 2014, Encana had 740.9 million common shares outstanding.

Eligible employees have been granted stock options to purchase common shares in accordance with Encana's Employee Stock Option Plan. As at December 31, 2013, there were approximately 29.5 million outstanding stock options with associated Tandem Stock Appreciation Rights ("TSARs") attached (15.5 million exercisable). A TSAR gives the option holder the right to receive a cash payment equal to the excess of the market price of Encana's common shares at the time of exercise over the original grant price. The exercise of a TSAR for a cash payment does not result in the issuance of any Encana common shares and therefore has no dilutive effect.

Historically, most holders of these options have elected to exercise their stock options as a TSAR in exchange for a cash payment.

Restricted Share Units ("RSUs") have been granted to eligible employees to receive an Encana common share, or the cash equivalent, as determined by Encana, upon vesting of the RSUs and in accordance with the terms of the RSU Plan and Grant Agreement. The value of one RSU is notionally equivalent to one Encana common share. As at December 31, 2013, there were approximately 8.6 million outstanding RSUs which vest three years from the date granted. The Company intends to settle vested RSUs in cash on the vesting date. A settlement in cash does not result in the issuance of any Encana common shares and therefore has no dilutive effect.

During 2013, Encana cancelled 767,327 common shares reserved for issuance to shareholders upon exchange of predecessor companies' shares. In accordance with the terms of the merger agreement which formed Encana, shares which have remained unexchanged were extinguished.

In March 2013, Encana amended its dividend reinvestment plan ("DRIP") to permit the Company to issue, from its treasury, Encana common shares to participating shareholders of the DRIP at a discount to the average market price for the applicable dividend payment date. Under the Company's DRIP, Encana issued 5.4 million common shares totaling $93 million during 2013.

On February 13, 2014, Encana announced that any future dividends in conjunction with the DRIP will be issued from Encana's treasury without a discount to the average market price unless otherwise announced by the Company via news release.

Dividends

Encana pays quarterly dividends to shareholders at the discretion of the Board of Directors. Dividend payments were $494 million or $0.67 per share for 2013 compared to $588 million or $0.80 per share for 2012 and 2011. As disclosed above, the dividends paid included $93 million in common shares for 2013, which were issued in lieu of cash dividends under the Company's DRIP.

On February 12, 2014, the Board declared a dividend of $0.07 per share payable on March 31, 2014 to common shareholders of record as of March 14, 2014.

Capital Structure

The Company's capital structure consists of shareholders' equity plus long-term debt, including the current portion. The Company's objectives when managing its capital structure are to maintain financial flexibility to preserve Encana's access to capital markets and its ability to meet financial obligations and finance internally generated growth, as well as potential acquisitions. Encana has a long-standing practice of maintaining capital discipline and managing and adjusting its capital structure according to market conditions to maintain flexibility while achieving the Company's objectives.

To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, issue new shares, issue new debt or repay existing debt. In managing its capital structure, the Company monitors several non-GAAP financial metrics as indicators of its overall financial strength, which are defined in the Non-GAAP Measures section of this MD&A. The financial metrics the Company currently monitors are below.

	2013	2012	2011
Net Debt to Debt Adjusted Cash Flow	**1.5x**	1.1x	1.6x
Debt to Debt Adjusted Cash Flow	**2.4x**	2.0x	1.8x
Debt to Adjusted EBITDA	**2.5x**	2.0x	1.9x
Debt to Adjusted Capitalization	**36%**	37%	33%

Contractual Obligations and Contingencies

Contractual Obligations

The following table outlines the Company's contractual obligations at December 31, 2013:

	Expected Future Payments						
($ millions, undiscounted)	2014	2015	2016	2017	2018	Thereafter	Total
Long-Term Debt [1]	1,000	-	-	700	705	4,700	7,105
Asset Retirement Obligation	68	61	70	68	57	3,982	4,306
Other Long-Term Obligations	87	87	88	89	90	1,893	2,334
Capital Leases	106	93	93	94	94	315	795
Obligations [2]	1,261	241	251	951	946	10,890	14,540
Transportation and Processing	967	985	896	896	848	4,379	8,971
Drilling and Field Services	292	106	71	41	38	35	583
Operating Leases	47	43	38	31	28	38	225
Commitments	1,306	1,134	1,005	968	914	4,452	9,779
Total Contractual Obligations	2,567	1,375	1,256	1,919	1,860	15,342	24,319
Sublease Recoveries	(43)	(43)	(44)	(44)	(44)	(939)	(1,157)

(1) Principal component only. See Note 12 to the Consolidated Financial Statements.

(2) The Company has recorded $10,312 million in liabilities related to these obligations.

Contractual obligations arising from long-term debt, asset retirement obligations, The Bow office building and capital leases are recognized on the Company's balance sheet. Further information can be found in the note disclosures to the Consolidated Financial Statements.

Other Long-Term Obligations relates to the 25-year lease agreement with a third party developer for The Bow office building. Encana has recognized the accumulated construction costs for The Bow office building as an asset with a related liability. In 2012, Encana commenced payments to the third party developer. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized. Encana has subleased part of The Bow office space to a subsidiary of Cenovus Energy Inc. ("Cenovus"). Sublease Recoveries in the table above include the amounts expected to be recovered from Cenovus. Encana's undiscounted payments for The Bow are $2,334 million, of which $1,157 million is expected to be recovered from Cenovus.

Capital Leases primarily includes the obligation related to the Deep Panuke Production Field Centre, which commenced commercial operations in December 2013 following issuance of the Production Acceptance Notice. Encana's undiscounted future lease payments total $687 million ($536 million discounted).

In addition to the Commitments disclosed in the table above, Encana has significant development commitments with joint venture partners, a portion of which may be satisfied by the Drilling and Field Services commitments included in the table above.

Further to the Commitments disclosed above, Encana also has obligations related to its risk management program and to fund its defined benefit pension and other post-employment benefit plans. Further information can be found in Note 21 to the Consolidated Financial Statements regarding the Company's risk management program. The Company expects to fund its 2014 commitments and obligations from Cash Flow and cash and cash equivalents.

Contingencies

Encana is involved in various legal claims and actions arising in the course of the Company's operations. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on Encana's financial position, cash flows or results of operations. If an unfavourable outcome were to occur, there exists the possibility of a material adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims.

Risk Management

Encana's business, prospects, financial condition, results of operation and cash flows, and in some cases its reputation, are impacted by risks that can be categorized as follows:

- financial risks;
- operational risks; and
- environmental, regulatory, reputational and safety risks.

Encana has created a new strategy to strengthen its position as a leading North American resource play company and grow shareholder value through a disciplined focus on generating profitable growth. Encana continues to focus on developing low-risk and low-cost long-life resource plays, which allows the Company to respond well to market uncertainties. Management adjusts financial and operational risk strategies to proactively respond to changing economic conditions and to mitigate or reduce risk.

Issues that can affect Encana's reputation are generally strategic or emerging issues that can be identified early and then appropriately managed, but they can also include unforeseen issues that must be managed on a more urgent basis. Encana takes a proactive approach to the identification and management of issues that affect the Company's reputation and has established appropriate policies, procedures, guidelines and responsibilities for identifying and managing these issues.

Financial Risks

Encana defines financial risks as the risk of loss or lost opportunity resulting from financial management and market conditions that could have an impact on Encana's business.

Financial risks include, but are not limited to:

- market pricing of natural gas and liquids;
- credit and liquidity;
- foreign exchange rates; and
- interest rates.

Encana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative financial instruments is governed under formal policies and is subject to limits established by the Board of Directors. All derivative financial agreements are with major global financial institutions or with corporate counterparties having investment grade credit ratings. Encana has in place policies and procedures with respect to the required documentation and approvals for the use of derivative financial instruments and specifically ties their use to the mitigation of financial risk to achieve investment returns and growth objectives, while maintaining prescribed financial metrics.

To partially mitigate commodity price risk, the Company may enter into transactions that fix, set a floor or set a floor and cap on prices. To help protect against regional price differentials, Encana executes transactions to manage the price differentials between its production areas and various sales points. Further information, including the details of Encana's financial instruments as at December 31, 2013, is disclosed in Note 21 to the Consolidated Financial Statements.

Counterparty credit risks are regularly and proactively managed. A substantial portion of Encana's credit exposure is with customers in the oil and gas industry or financial institutions. This credit exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio, including credit practices that limit transactions and grant payment terms according to industry standards and counterparties' credit quality.

The Company manages liquidity risk using cash and debt management programs. The Company has access to cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities and debt capital markets. Encana closely monitors the Company's ability to access cost-effective credit and ensures that sufficient liquidity is in place to fund capital expenditures and dividend payments. The Company minimizes its liquidity risk by managing its capital structure which may include adjusting capital spending, adjusting dividends paid to shareholders, issuing new shares, issuing new debt or repaying existing debt.

As a means of mitigating the exposure to fluctuations in the U.S./Canadian dollar exchange rate, Encana may enter into foreign exchange contracts. Realized gains or losses on these contracts are recognized on settlement. By maintaining U.S. and Canadian operations, Encana has a natural hedge to some foreign exchange exposure.

Encana also maintains a mix of both U.S. dollar and Canadian dollar debt. This helps to offset the exposure to the fluctuations in the U.S./Canadian dollar exchange rate. In addition to direct issuance of U.S. dollar denominated debt, the Company may enter into cross currency swaps on a portion of its debt as a means of managing the U.S./Canadian dollar debt mix.

The Company may partially mitigate its exposure to interest rate changes by holding a mix of both fixed and floating rate debt. Encana may enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

Operational Risks

Operational risks are defined as the risk of loss or lost opportunity resulting from the following:

- operating activities;
- capital activities, including the ability to complete projects; and
- reserves and resources replacement.

The Company's ability to operate, generate cash flows, complete projects, and value reserves and resources is subject to financial risks, including commodity prices mentioned above, continued market demand for its products and other risk factors outside of its control. These factors include: general business and market conditions; economic recessions and financial market turmoil; the overall state of the capital markets, including investor appetite for investments in the oil and gas industry generally and the Company's securities in particular; the ability to secure and maintain cost-effective financing for its commitments; legislative, environmental and regulatory matters; unexpected cost increases; royalties; taxes; volatility in natural gas and liquids prices; partner funding for their share of joint venture and partnership commitments; the availability of drilling and other equipment; the ability to access lands; the ability to access water for hydraulic fracturing operations; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; technology failures; accidents; the availability of skilled labour; and reservoir quality. If Encana fails to acquire or find additional natural gas and liquids reserves and resources, its reserves, resources and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and resources and acquiring, discovering or developing additional reserves and resources. To mitigate these risks, as part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk.

In addition, Encana undertakes a thorough review of previous capital programs to identify key learnings, which often include operational issues that positively and negatively impact project results. Mitigation plans are developed for the operational issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these results are analyzed for Encana's capital program with the results and identified learnings shared across the Company.

A peer review process is used to ensure that capital projects are appropriately risked and that knowledge is shared across the Company. Peer reviews are undertaken primarily for exploration projects and early stage resource plays, although they may occur for any type of project.

When making operating and investing decisions, Encana's business model allows flexibility in capital allocation to optimize investments focused on project returns, long-term value creation and risk mitigation. Encana also mitigates operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program.

Environmental, Regulatory, Reputational and Safety Risks

The Company is committed to safety in its operations and has high regard for the environment and stakeholders, including regulators. The Company's business is subject to all of the operating risks normally associated with the exploration for, development of and production of natural gas, oil and NGLs and the operation of midstream facilities. When assessing the materiality of environmental risk factors, Encana takes into account a number of qualitative and quantitative factors, including, but not limited to, the financial, operational, reputational and regulatory aspects of each identified risk factor. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, Encana maintains a system that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to Senior Management and the Board of Directors. The Corporate Responsibility, Environment, Health and Safety Committee of Encana's Board of Directors provides recommended environmental policies for approval by Encana's Board of Directors and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and audits, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to environmental events and remediation/reclamation strategies are utilized to restore the environment.

Encana's operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion, including hydraulic fracturing and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Changes in government regulation could impact the Company's existing and planned projects as well as impose a cost of compliance.

One of the processes Encana monitors relates to hydraulic fracturing. Hydraulic fracturing is used throughout the oil and gas industry where fracturing fluids are utilized to develop the reservoir. This process has been used in the oil and gas industry for approximately 60 years. Encana uses multiple techniques to fully understand the effect of each hydraulic fracturing operation it conducts. In all Encana operations, rigorous water management and protection is an essential part of this process.

Hydraulic fracturing processes are strictly regulated by various state and provincial government agencies. Encana meets or exceeds the requirements set out by the regulators. 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 have not provided specific details with respect to any significant actual, proposed or contemplated changes to hydraulic fracturing regulations. However, chemical disclosure requirements are increasing in many of the jurisdictions in which the Company operates.

In the state of Colorado, several cities, including Boulder, Longmont, Fort Collins, Lafayette and Broomfield as well as the County of Boulder, have passed local ordinances limiting or banning certain oil and gas activities, including hydraulic fracturing. These local rule-making initiatives have not significantly impacted the Company's operations or development plans in the state and are not anticipated to have a negative impact on the Company's operations in the future. On January 21, 2014, a ballot initiative was filed in the state seeking to transfer the authority to regulate all for-profit companies to local government and specifically stating that local ordinances pre-empt all international, federal and state laws, except for individual fundamental rights. Though broad in nature, the ballot initiative is understood to be primarily intended to restrict oil and gas development in the state. This and other possible measures could make certain Colorado jurisdictions inaccessible to drilling in the future. Therefore, it is possible that the Company's operations in Colorado could be impeded should such initiatives succeed. Encana continues to work with state and local governments, academics and industry leaders to develop and respond to hydraulic fracturing related concerns in Colorado. The Company recognizes that additional hydraulic fracturing ballot initiatives are a possibility and will continue to monitor and respond to these developments in 2014.

In June 2013, the U.S. Environmental Protection Agency (the "EPA") announced it has suspended its study of the potential environmental impacts of hydraulic fracturing, including the impacts on drinking water sources and public health, at Encana's Pavillion natural gas field in Wyoming. The agency has stated that the results in its 2011 draft report were inconclusive and it does not plan to finalize, seek peer review of or rely upon the conclusions of the draft report. Further, no aspects of the draft report will be incorporated into the EPA's larger ongoing national study of hydraulic fracturing. Instead, the EPA will support additional scientific investigation of the Pavillion groundwater being led by the Wyoming Department of Environmental Quality and the Wyoming Oil and Gas Conservation Commission. Any implication of a potential connection between hydraulic fracturing and groundwater quality may potentially subject Encana to regulatory, operational and/or reputation risks.

Encana is committed to and supports the disclosure of hydraulic fracturing chemical information. Encana participates in the FracFocus Chemical Disclosure Registry (the "Registry") in the U.S. and the Alberta and British Columbia versions of the Registry. Encana works collaboratively with industry peers, trade associations, fluid suppliers and regulators to identify, develop and advance responsible hydraulic fracturing best practices. More information on hydraulic fracturing can be accessed on the Company's website at www.encana.com.

Climate Change Regulations

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases ("GHG") and certain other air emissions. While some jurisdictions have provided details on these regulations, it is anticipated that other jurisdictions will announce emission reduction plans in the future. As these federal and regional programs are under development, Encana is unable to predict the total impact of the potential regulations upon its business. Therefore, it is possible that the Company could face increases in operating and capital costs in order to comply with GHG emissions legislation. However, Encana will continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Alberta Government has set targets for GHG emission reductions. In March 2007, regulations were amended to require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline starting July 1, 2007. To comply, companies can make operating improvements, purchase carbon offsets or make a C$15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. In Alberta, Encana has one facility covered under the emissions regulations. The forecast cost of carbon associated with the Alberta regulations is not material to Encana at this time and is being actively managed.

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' was applied to virtually all fossil fuels, including diesel, natural gas, coal, propane and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate started at C$10 per tonne of carbon equivalent emissions and has risen to C$30 per tonne at present. The forecast cost of carbon associated with the British Columbia regulations is not material to Encana at this time and is being actively managed.

The Canadian federal government has announced that it will align GHG emission reduction targets with the U.S. The Canadian federal government has taken a sector-specific approach and, while progress has been made working with industry and the provinces on the development of oil and gas sector-specific regulations, the federal government has not committed to a definitive timeline for implementation and/or release of legislation. Encana will continue to monitor these developments during 2014.

While the U.S federal government has noted climate change action as a priority for the current administration's upcoming second term, direction given to the EPA to date has focused on establishing proposed carbon emission standards, regulations or guidelines related to power plants. To date, no legislative or regulatory announcements have been made that would materially impact oil and natural gas activities. Encana will continue to monitor any developments during 2014.

Encana intends to continue its activity to reduce its emissions intensity and improve its energy efficiency. The Company's efforts with respect to emissions management are founded with a focus on energy efficiency, the development of technology to reduce GHG emissions and active involvement in the creation of industry best practices.

Encana has a proactive strategy for addressing the implications of emerging carbon regulations which is composed of three principal elements:

- *Active Cost Management.* When regulations are implemented, a cost is placed on Encana's emissions (or a portion thereof) and, while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking and attention to fuel consumption help to support and drive the Company's focus on cost reduction.

- *Anticipate and Respond to Price Signals.* As regulatory regimes for GHGs develop in the jurisdictions where Encana operates, inevitably price signals begin to emerge. The Company maintains an Environmental Efficiency Initiative in an effort to improve the energy efficiency of its operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon, Encana is also attempting, where appropriate, to realize the associated value of its reduction projects.

- *Work with Industry Groups.* Encana continues to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, the Company gains useful knowledge that allows it to explore different strategies for managing its emissions and costs. These scenarios influence Encana's long-range planning and its analyses on the implications of regulatory trends.

Encana monitors developments in emerging climate change policy and legislation, and considers the associated costs of carbon in its strategic planning. Management and the Board of Directors review the impact of a variety of carbon constrained scenarios on its strategy, with a current price range from approximately $10 to $80 per tonne of emissions applied to a range of emissions coverage levels. Encana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, Encana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

Encana recognizes that there is a cost associated with carbon emissions. Encana is confident that GHG regulations and the cost of carbon at various price levels have been adequately considered as part of its business planning and scenarios analyses. Encana believes that the resource play strategy is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. Encana is committed to transparency with its stakeholders and will keep them apprised of how these issues affect operations. Additional detail on Encana's GHG emissions is available in the Corporate Responsibility Report that is available on the Company's website at www.encana.com.

Accounting Policies and Estimates

Critical Accounting Estimates

Management is required to make judgments, assumptions and estimates in applying its accounting policies and practices, which have a significant impact on the financial results of the Company. A summary of Encana's significant accounting policies can be found in Note 1 to the Consolidated Financial Statements for the year ended December 31, 2013. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining Encana's financial results.

Upstream Assets and Reserves

Encana follows U.S. GAAP full cost accounting for natural gas, oil and NGL activities. Reserves estimates can have a significant impact on net earnings, as they are a key input to the Company's depletion and ceiling test impairment calculations. A downward revision in reserves estimates may increase depletion expense and may also result in a ceiling test impairment. A ceiling test impairment is recognized in net earnings when the carrying amount of a country cost centre exceeds the country cost centre ceiling. The carrying amount of a cost centre includes capitalized costs of proved oil and gas properties, net of accumulated depletion and the related deferred income taxes. The cost centre ceiling is the sum of the estimated after-tax future net cash flows from proved reserves as calculated under SEC requirements, using the 12-month average trailing prices and unescalated future development and production costs, discounted at 10 percent, plus unproved property costs. The 12-month average trailing price is calculated as the average of the price on the first day of each month within the trailing 12-month period. Any excess of the carrying amount over the calculated ceiling is recognized as an impairment in net earnings. During 2012 and 2011, Encana recorded ceiling test impairments, which are discussed further in the Divisional Results section of this MD&A.

Annually, all of Encana's natural gas, oil and NGL reserves and resources are evaluated and reported on by independent qualified reserves evaluators. The estimation of reserves is a subjective process. Estimates are based on engineering data, projected future rates of production, and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels and economics of recovery.

The Company believes that the discounted after-tax future net cash flows from proved reserves required to be used in the ceiling test calculation are not indicative of the fair market value of Encana's oil and gas properties or of the future net cash flows expected to be generated from such properties. The discounted after-tax future net cash flows do not consider the value of unproved properties, the value of probable or possible reserves or future changes in commodity prices. Encana manages its business using estimates of reserves and resources based on forecast prices and costs.

Asset Retirement Obligation

Asset retirement obligations are those legal obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, offshore production platforms and natural gas processing plants. The fair value of estimated asset retirement obligations is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the initially estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. Changes in the estimated obligation resulting from revisions to estimated timing or amount of future cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

The asset retirement obligation is estimated by discounting the expected future cash flows of the settlement. The discounted cash flows are based on estimates of such factors as reserves lives, retirement costs, timing of settlements, credit-adjusted risk-free rates and inflation rates. These estimates will impact net earnings through accretion of the asset retirement obligation in addition to depletion of the asset retirement cost included in property, plant and equipment. Actual expenditures incurred are charged against the accumulated asset retirement obligation.

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually at December 31. Goodwill and all other assets and liabilities are allocated to reporting units, which are Encana's country cost centres. To assess impairment, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than its related fair value then goodwill is written down to the reporting unit's implied fair value of goodwill. The implied fair value of goodwill is determined by deducting the fair value of the reporting unit's assets and liabilities from the fair value of the reporting unit as if the reporting entity had been acquired in a business combination. Any excess of the carrying value of goodwill over the implied fair value of goodwill is recognized as an impairment and charged to net earnings. Subsequent measurement of goodwill is at cost less accumulated impairments.

The fair value used in the impairment test is based on estimates of discounted future cash flows which involves assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates. Encana has assessed its goodwill for impairment at December 31, 2013 and has determined that no write-down is required.

Income Taxes

Encana follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the enacted income tax rates and laws expected to apply when the assets are realized and liabilities are settled. Current income taxes are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates and laws enacted at the end of the reporting period. The effect of a change in the enacted tax rates or laws is recognized in net earnings in the period of enactment.

Deferred income tax assets are routinely assessed for realizability. If it is more likely than not that deferred tax assets will not be realized, a valuation allowance is recorded to reduce the deferred tax assets. Encana considers available positive and negative evidence when assessing the realizability of deferred tax assets, including historic and expected future taxable earnings, available tax planning strategies and carry forward periods. The assumptions used in determining expected future taxable earnings are consistent with those used in the goodwill impairment assessment.

Encana's interim income tax expense is determined using an estimated annual effective income tax rate applied to year-to-date net earnings before income tax plus the effect of legislative changes and amounts in respect of prior periods. The estimated annual effective income tax rate is impacted by the expected annual earnings, statutory rate and other foreign differences, non-taxable capital gains and losses, tax differences on divestitures and transactions and partnership tax allocations in excess of funding.

Encana recognizes the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination by a taxing authority. A recognized tax position is initially and subsequently measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon settlement with a taxing authority. Liabilities for unrecognized tax benefits that are not expected to be settled within the next 12 months are included in other liabilities and provisions.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty and the interpretations can impact net earnings through the income tax expense arising from the changes in deferred income tax assets or liabilities.

Derivative Financial Instruments

As described in the Risk Management section of this MD&A, derivative financial instruments are used by Encana to manage its exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. The Company's policy is not to utilize derivative financial instruments for speculative purposes.

Derivative financial instruments are measured at fair value with changes in fair value recognized in net earnings. The fair values recorded in the Consolidated Balance Sheet reflect netting the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. Realized gains or losses from financial derivatives related to natural gas and oil commodity prices are recognized in revenues as the contracts are settled. Realized gains or losses from financial derivatives related to power commodity prices are recognized in transportation and processing expense as the related power contracts are settled. Unrealized gains and losses are recognized in revenues and transportation and processing expense accordingly, at the end of each respective reporting period based on the changes in fair value of the contracts.

The estimate of fair value of all derivative instruments is based on quoted market prices or, in their absence, third party market indications and forecasts. The estimated fair value of financial assets and liabilities is subject to measurement uncertainty.

Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

As of January 1, 2013, Encana adopted the following accounting standards updates issued by the Financial Accounting Standards Board ("FASB"), which have not had a material impact on the Company's Consolidated Financial Statements:

- Accounting Standards Update 2011-11, *Disclosures about Offsetting Assets and Liabilities,* and Accounting Standards Update 2013-01, *Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities*, require disclosure of both gross and net information about certain financial instruments eligible for offset in the balance sheet and certain financial instruments subject to master netting arrangements. The amendments have been applied retrospectively.

- Accounting Standards Update 2013-02, *Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income,* requires enhanced disclosures about amounts reclassified out of accumulated other comprehensive income. The amendments have been applied prospectively.

New Standards Issued Not Yet Adopted

As of January 1, 2014, Encana will be required to adopt the following accounting standards updates issued by the FASB, which are not expected to have a material impact on the Company's Consolidated Financial Statements:

- Accounting Standards Update 2013-04, *Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date*, clarifies guidance for the recognition, measurement and disclosure of liabilities resulting from joint and several liability arrangements. The amendments will be applied retrospectively.

- Accounting Standards Update 2013-05, *Parent's Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity*, clarifies the applicable guidance for certain transactions that result in the release of the cumulative translation adjustment into net earnings. The amendments will be applied prospectively.

- 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*, clarifies that a liability related to an unrecognized tax benefit or portions thereof should be presented as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward, except under specific situations. The amendments will be applied prospectively.

Non-GAAP Measures

Certain measures in this document do not have any standardized meaning as prescribed by U.S. GAAP and therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures are commonly used in the oil and gas industry and by Encana to provide shareholders and potential investors with additional information regarding the Company's liquidity and its ability to generate funds to finance its operations. Non-GAAP measures include: Cash Flow; Cash Flow per share - diluted; Operating Earnings; Operating Earnings per share - diluted; Revenues, Net of Royalties, Excluding Unrealized Hedging; Net Debt to Debt Adjusted Cash Flow; Debt to Debt Adjusted Cash Flow; Debt to Adjusted EBITDA; and Debt to Adjusted Capitalization. Management's use of these measures is discussed further below.

Cash Flow

Cash Flow is a non-GAAP measure commonly used in the oil and gas industry and by Encana to assist Management and investors in measuring the Company's ability to finance capital programs and meet financial obligations. Cash Flow is defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and cash tax on sale of assets.

	2013					2012					2011
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Cash From (Used in) Operating Activities	**$ 2,289**	**$ 462**	**$ 935**	**$ 554**	**$ 338**	$ 3,107	$ 717	$ 1,142	$ 631	$ 617	$ 3,927
(Add back) deduct:											
Net change in other assets and liabilities	**(80)**	**(21)**	**(15)**	**(22)**	**(22)**	(78)	(23)	(9)	(26)	(20)	(160)
Net change in non-cash working capital	**(179)**	**(183)**	**300**	**(81)**	**(215)**	(323)	(56)	242	(134)	(375)	(15)
Cash tax on sale of assets	**(33)**	**(11)**	**(10)**	**(8)**	**(4)**	(29)	(13)	(4)	(3)	(9)	(114)
Cash Flow	**$ 2,581**	**$ 677**	**$ 660**	**$ 665**	**$ 579**	$ 3,537	$ 809	$ 913	$ 794	$ 1,021	$ 4,216

Operating Earnings

Operating Earnings is a non-GAAP measure that adjusts Net Earnings by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. Operating Earnings is commonly used in the oil and gas industry and by Encana to provide investors with information that is more comparable between periods.

Operating Earnings is defined as Net Earnings excluding non-recurring or non-cash items that Management believes reduces the comparability of the Company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, foreign exchange gains/losses, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective tax rate.

	2013					2012					2011
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Net Earnings (Loss)	**$ 236**	**$ (251)**	**$ 188**	**$ 730**	**$ (431)**	$(2,794)	$ (80)	$(1,244)	$(1,482)	$ 12	$ 5
After-tax (addition) / deduction:											
Unrealized hedging gain (loss)	**(232)**	**(209)**	**(89)**	**332**	**(266)**	(1,002)	(72)	(428)	(547)	45	600
Impairments	**(16)**	**-**	**(16)**	**-**	**-**	(3,188)	(300)	(1,193)	(1,695)	-	(1,687)
Restructuring charges	**(64)**	**(64)**	**-**	**-**	**-**	-	-	-	-	-	-
Non-operating foreign exchange gain (loss)	**(282)**	**(124)**	**105**	**(162)**	**(101)**	92	(66)	162	(90)	86	(99)
Income tax adjustments	**28**	**(80)**	**38**	**313**	**(243)**	307	62	(48)	652	(359)	-
Operating Earnings	**$ 802**	**$ 226**	**$ 150**	**$ 247**	**$ 179**	$ 997	$ 296	$ 263	$ 198	$ 240	$ 1,191

Revenues, Net of Royalties, Excluding Unrealized Hedging

Revenues, Net of Royalties, Excluding Unrealized Hedging is a non-GAAP measure that adjusts revenues, net of royalties for unrealized hedging gains/losses. Unrealized hedging gains/losses result from the fair value changes in unsettled derivative financial contracts. Management monitors Revenues, Net of Royalties, Excluding Unrealized Hedging as it reflects the realized hedging impact of the Company's settled financial contracts.

	2013					2012					2011
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Revenues, Net of Royalties	**$ 5,858**	**$ 1,423**	**$ 1,392**	**$ 1,984**	**$1,059**	$ 5,160	$1,605	$ 1,025	$ 731	$ 1,799	$ 8,467
(Add) / deduct:											
Unrealized hedging gain (loss), before tax	**(347)**	**(296)**	**(126)**	**461**	**(386)**	(1,441)	(118)	(598)	(795)	70	854
Revenues, Net of Royalties, Excluding Unrealized Hedging	**$ 6,205**	**$ 1,719**	**$ 1,518**	**$ 1,523**	**$1,445**	$ 6,601	$1,723	$ 1,623	$ 1,526	$ 1,729	$ 7,613

Net Debt to Debt Adjusted Cash Flow

Net Debt to Debt Adjusted Cash Flow is a non-GAAP measure monitored by Management as an indicator of the Company's overall financial strength. Net Debt is a non-GAAP measure defined as long-term debt, including current portion, less cash and cash equivalents. Debt Adjusted Cash Flow is a non-GAAP measure defined as Cash Flow on a trailing 12-month basis excluding interest expense after tax.

($ millions)		**2013**		2012		2011
Debt	**$**	**7,124**	$	7,675	$	8,150
Less: Cash and Cash Equivalents		**2,566**		3,179		800
Net Debt		**4,558**		4,496		7,350
Cash Flow		**2,581**		3,537		4,216
Interest Expense, after tax		**421**		391		344
Debt Adjusted Cash Flow	**$**	**3,002**	$	3,928	$	4,560
Net Debt to Debt Adjusted Cash Flow		**1.5x**		1.1x		1.6x

Debt to Debt Adjusted Cash Flow

Debt to Debt Adjusted Cash Flow is a non-GAAP measure monitored by Management as an indicator of the Company's overall financial strength. Debt Adjusted Cash Flow is a non-GAAP measure defined as Cash Flow on a trailing 12-month basis excluding interest expense after tax.

($ millions)		**2013**		2012		2011
Debt	**$**	**7,124**	$	7,675	$	8,150
Cash Flow		**2,581**		3,537		4,216
Interest Expense, after tax		**421**		391		344
Debt Adjusted Cash Flow	**$**	**3,002**	$	3,928	$	4,560
Debt to Debt Adjusted Cash Flow		**2.4x**		2.0x		1.8x

Debt to Adjusted EBITDA

Debt to Adjusted EBITDA is a non-GAAP measure monitored by Management as an indicator of the Company's overall financial strength. Adjusted EBITDA is a non-GAAP measure defined as trailing 12-month Net Earnings before income taxes, foreign exchange gains or losses, interest, accretion of asset retirement obligation, DD&A, impairments, unrealized hedging gains and losses and other expenses.

($ millions)		2013		2012		2011
Debt	$	7,124	$	7,675	$	8,150
Net Earnings (Loss)		236		(2,794)		5
Add (deduct):						
Interest		563		522		468
Income tax expense (recovery)		(248)		(2,037)		17
Depreciation, depletion and amortization		1,565		1,956		2,282
Impairments		21		4,695		2,249
Accretion of asset retirement obligation		53		53		50
Foreign exchange (gain) loss, net		325		(107)		133
Unrealized (gain) loss on risk management		345		1,465		(879)
Other		(6)		1		21
Adjusted EBITDA	$	2,854	$	3,754	$	4,346
Debt to Adjusted EBITDA		2.5x		2.0x		1.9x

Debt to Adjusted Capitalization

Debt to Adjusted Capitalization is a non-GAAP measure, which adjusts capitalization for historical ceiling test impairments that were recorded as at December 31, 2011. Management monitors Debt to Adjusted Capitalization as a proxy for Encana's financial covenant under its credit facility agreements which require debt to adjusted capitalization to be less than 60 percent. Adjusted Capitalization includes debt, shareholders' equity and an equity adjustment for cumulative historical ceiling test impairments recorded as at December 31, 2011 in conjunction with the Company's January 1, 2012 adoption of U.S. GAAP.

($ millions)		2013		2012		2011
Debt	$	7,124	$	7,675	$	8,150
Shareholders' Equity		5,147		5,295		8,578
Equity Adjustment for Impairments at December 31, 2011		7,746		7,746		7,746
Adjusted Capitalization	$	20,017	$	20,716	$	24,474
Debt to Adjusted Capitalization		36%		37%		33%

Advisory

Forward-Looking Statements

In the interest of providing Encana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of Encana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project", "objective", "strategy", "strives", "agreed to" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: achieving the Company's focus on developing its strong portfolio of resource plays producing natural gas, oil and NGLs; commitment to growing long-term shareholder value through a disciplined focus on generating profitable growth; pursuing its key business objectives of balancing its commodity mix, focusing capital investments in high return, scalable projects, maintaining portfolio flexibility, maximizing profitability through operating efficiencies, reducing costs and preserving balance sheet strength; the expectation that there will be no significant changes in reportable segments as a result of the new business strategy; the realignment of the Company's business strategy and corporate organizational structure and success thereof; the Company's plans to transfer its royalty business into a new company through an IPO, including the expected future activities of the new company following the transaction, the anticipated benefits of the transaction to Encana and its shareholders, Encana's expected ownership level in the new company, that applicable approvals will be obtained and the timing and success of such offering; the ability to continue entering prospective plays early and leveraging technology to unlock resources and build the underlying productive capacity at low cost; anticipated revenues and operating expenses; improving operating efficiencies, fostering technological innovation, lowering cost structures and success of resource play hub model; the Company's continued focus on developing low-risk and low-cost long-life resource plays; the anticipated proceeds from various joint venture, partnership and other agreements entered into by the Company, including their successful implementation, expected future benefits and the Company's ability to fund future development costs associated with those agreements; anticipated dividends, potential future discounts to market price in connection with the Company's DRIP; anticipated oil, natural gas and NGLs prices; anticipated third party purchases and sales; projections contained in the 2014 Corporate Guidance (including estimates of cash flow including per share, natural gas, oil and NGLs production, capital investment and its allocation, net divestitures, operating costs, and 2014 estimated sensitivities of cash flow and operating earnings); estimates of reserves and resources; expectation that the discounted after-tax future net cash flows from proved reserves used in ceiling test calculations is not indicative of the fair market value of Encana's oil and gas properties or of the future net cash flows expected to be generated from such properties; projections relating to the adequacy of the Company's provision for taxes and legal claims; the flexibility of capital spending plans and the source of funding therefor; anticipated access to capital markets and ability to meet financial obligations and finance growth; the benefits of the Company's risk management program, including the impact of derivative financial instruments; projections that the Company has access to cash and cash equivalents and a range of funding at competitive rates; the Company's ability to meet payment terms of its suppliers and be in compliance with all financial covenants under its credit facility agreements; anticipated debt repayments and the ability to make such repayments in cash; expectations surrounding environmental legislation including regulations relating to climate change and hydraulic fracturing and the impact such regulations could have on the Company and the results of additional scientific investigations of the Pavillion groundwater; anticipated flexibility to refinance maturing long-term debt or repay debt maturities from existing sources of liquidity; expectation to fund 2014 commitments from cash flow, cash and cash equivalents; expectations regarding accessing the debt capital market in Canada in the near term; the anticipated effect of the Company's risk mitigation policies, systems, processes and insurance program; the Company's ability to manage its Net Debt to Debt Adjusted Cash Flow, Debt to Debt Adjusted Cash Flow, Debt to Adjusted EBITDA and Debt to Adjusted Capitalization ratios; and the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company and its financial statements.

Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of, and assumptions regarding natural gas and liquids prices, including substantial or extended decline of the same and their adverse effect on the Company's operations and financial condition and the value and amount of its reserves; assumptions based upon the Company's current guidance; fluctuations in currency and interest rates; risk that the Company may not conclude divestitures of certain assets or other transactions or receive amounts contemplated under the transaction agreements (such transactions may include third party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "partnerships" or "joint ventures" and the funds received in respect thereof which Encana may refer to from time to time as "proceeds", "deferred purchase price" and/or "carry capital", regardless of the legal form) as a result of various conditions not being met; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; marketing margins; potential disruption or unexpected technical difficulties in developing new facilities; unexpected cost increases or technical difficulties in constructing or modifying processing facilities; risks associated with technology; the Company's ability to acquire or find additional reserves; hedging activities resulting in realized and unrealized losses; business interruption and casualty losses; risk of the Company not operating all of its properties and assets; counterparty risk; downgrade in credit rating and its adverse effects; liability for indemnification obligations to third parties; variability of dividends to be paid; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company operates; terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; risk arising from price basis differential; risk arising from inability to enter into attractive hedges to protect the Company's capital program; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana. Without limiting the generality of the foregoing, there can be no assurance that Encana will ultimately conduct an IPO, or, if a new company is created, the final particulars thereof, including without limitation, the number, value or location of the fee simple mineral title lands and associated royalty interests that would be proposed to be transferred to a new company, the size of the retained interest that Encana would hold initially or in the future in the new company, and other arrangements that would be proposed or exist as between Encana and the new company. Encana's determination to create a new company is subject to a number of risks and uncertainties, including without limitation, those relating to approval by Encana's Board of Directors, due diligence, favourable market conditions and stock exchange, regulatory and third party approvals. Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date hereof and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Forward-looking information respecting anticipated 2014 cash flow for Encana is based upon, among other things, achieving average production for 2014 of between 2.6 Bcf/d and 2.8 Bcf/d of natural gas and 70,000 bbls/d to 75,000 bbls/d of liquids, commodity prices for natural gas and liquids based on NYMEX $3.75 per MMBtu and WTI of $95 per bbl, an estimated U.S./Canadian dollar foreign exchange rate of $0.95 and a weighted average number of outstanding shares for Encana of approximately 741 million.

Assumptions relating to forward-looking statements generally include Encana's current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

Encana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that Encana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in Encana's news release dated February 13, 2014, which is available on Encana's website at www.encana.com, on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Oil and Gas Information

National Instrument 51-101 of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. The Canadian protocol disclosure is contained in Appendix A and under "Narrative Description of the Business" in the AIF. Encana obtained an exemption dated January 4, 2011 from certain requirements of NI 51-101 to permit it to provide certain disclosure prepared in accordance with U.S. disclosure requirements, in addition to the Canadian protocol disclosure. The Company's U.S. GAAP U.S. protocol disclosure is included in Note 24 (unaudited) to the Company's Consolidated Financial Statements for the year ended December 31, 2013 and in Appendix D of the AIF.

A description of the primary differences between the disclosure requirements under the Canadian standards and under the U.S. standards is set forth under the heading "Reserves and Other Oil and Gas Information" in the AIF.

Natural Gas, Oil and NGLs Conversions

In this document, certain oil and NGL volumes have been converted to Bcfe on the basis of one bbl to six Mcf. Cubic feet equivalent may be misleading, particularly if used in isolation. A conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

Given that the value ratio based on the current price of 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.

Resource Play

Resource play is a term used by Encana to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate.

Currency and References to Encana

All information included in this document and the Consolidated Financial Statements and comparative information is shown on a U.S. dollar, after royalties basis, unless otherwise noted. References to C$ are to Canadian dollars. Encana's financial results are consolidated in Canadian dollars, however, the Company has adopted the U.S. dollar as its reporting currency to facilitate a more direct comparison to other North American oil and gas companies. All proceeds from divestitures are provided on a before-tax basis.

For convenience, references in this document to "Encana", the "Company", "we", "us", "our" and "its" may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships ("Subsidiaries") of Encana Corporation, and the assets, activities and initiatives of such Subsidiaries.

Additional Information

Further information regarding Encana Corporation, including its Annual Information Form, can be accessed under the Company's public filings found on SEDAR at www.sedar.com, on EDGAR at www.sec.gov and on the Company's website at www.encana.com.

Condensed Consolidated Statement of Earnings *(unaudited)*

($ millions, except per share amounts)		Three Months Ended December 31, 2013	2012	Twelve Months Ended December 31, 2013	2012
Revenues, Net of Royalties	*(Note 3)*	**$ 1,423**	$ 1,605	**$ 5,858**	$ 5,160
Expenses	*(Note 3)*				
Production and mineral taxes		**37**	36	**134**	105
Transportation and processing		**405**	318	**1,476**	1,231
Operating		**221**	183	**859**	794
Purchased product		**138**	84	**441**	349
Depreciation, depletion and amortization		**388**	445	**1,565**	1,956
Impairments	*(Note 8)*	**-**	487	**21**	4,695
Accretion of asset retirement obligation	*(Note 11)*	**13**	13	**53**	53
Administrative	*(Note 14)*	**167**	93	**439**	392
Interest	*(Note 5)*	**139**	134	**563**	522
Foreign exchange (gain) loss, net	*(Note 6)*	**160**	58	**325**	(107)
Other		**4**	3	**(6)**	1
		1,672	1,854	**5,870**	9,991
Net Earnings (Loss) Before Income Tax		**(249)**	(249)	**(12)**	(4,831)
Income tax expense (recovery)	*(Note 7)*	**2**	(169)	**(248)**	(2,037)
Net Earnings (Loss)		**$ (251)**	$ (80)	**$ 236**	$ (2,794)
Net Earnings (Loss) per Common Share	*(Note 12)*				
Basic		**$ (0.34)**	$ (0.11)	**$ 0.32**	$ (3.79)
Diluted		**$ (0.34)**	$ (0.11)	**$ 0.32**	$ (3.79)

Condensed Consolidated Statement of Comprehensive Income *(unaudited)*

($ millions)		Three Months Ended December 31, 2013	2012	Twelve Months Ended December 31, 2013	2012
Net Earnings (Loss)		**$ (251)**	$ (80)	**$ 236**	$ (2,794)
Other Comprehensive Income (Loss), Net of Tax					
Foreign currency translation adjustment	*(Note 13)*	**(27)**	(5)	**(46)**	81
Pension and other post-employment benefit plans	*(Notes 13, 16)*	**52**	5	**60**	13
Other Comprehensive Income (Loss)		**25**	-	**14**	94
Comprehensive Income (Loss)		**$ (226)**	$ (80)	**$ 250**	$ (2,700)

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Balance Sheet *(unaudited)*

($ millions)		**As at December 31, 2013**	As at December 31, 2012
Assets			
Current Assets			
Cash and cash equivalents		**$ 2,566**	$ 3,179
Accounts receivable and accrued revenues		**988**	1,236
Risk management	*(Note 18)*	**56**	479
Income tax receivable		**562**	560
Deferred income taxes		**118**	23
		4,290	5,477
Property, Plant and Equipment, at cost:	*(Note 8)*		
Natural gas and oil properties, based on full cost accounting			
Proved properties		**51,603**	50,953
Unproved properties		**1,068**	1,295
Other		**3,148**	3,379
Property, plant and equipment		**55,819**	55,627
Less: Accumulated depreciation, depletion and amortization		**(45,784)**	(45,876)
Property, plant and equipment, net	*(Note 3)*	**10,035**	9,751
Cash in Reserve		**10**	54
Other Assets		**526**	466
Risk Management	*(Note 18)*	**204**	111
Deferred Income Taxes		**939**	1,116
Goodwill	*(Note 3)*	**1,644**	1,725
	(Note 3)	**$ 17,648**	$ 18,700
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts payable and accrued liabilities		**$ 1,895**	$ 2,003
Income tax payable		**29**	45
Risk management	*(Note 18)*	**25**	5
Current portion of long-term debt	*(Note 9)*	**1,000**	500
Deferred income taxes		**3**	59
		2,952	2,612
Long-Term Debt	*(Note 9)*	**6,124**	7,175
Other Liabilities and Provisions	*(Note 10)*	**2,520**	2,672
Risk Management	*(Note 18)*	**5**	10
Asset Retirement Obligation	*(Note 11)*	**900**	936
		12,501	13,405
Commitments and Contingencies	*(Note 19)*		
Shareholders' Equity			
Share capital - authorized unlimited common shares, without par value			
2013 issued and outstanding: 740.9 million shares (2012: 736.3 million shares)	*(Note 12)*	**2,445**	2,354
Paid in surplus		**15**	10
Retained earnings		**2,003**	2,261
Accumulated other comprehensive income	*(Note 13)*	**684**	670
Total Shareholders' Equity		**5,147**	5,295
		$ 17,648	$ 18,700

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Changes in Shareholders' Equity *(unaudited)*

Twelve Months Ended December 31, 2013 ($ millions)		Share Capital	Paid in Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2012		**$ 2,354**	**$ 10**	**$ 2,261**	**$ 670**	**$ 5,295**
Share-Based Compensation	*(Note 15)*	**-**	**3**	**-**	**-**	**3**
Net Earnings (Loss)		**-**	**-**	**236**	**-**	**236**
Common Shares Cancelled	*(Note 12)*	**(2)**	**2**	**-**	**-**	**-**
Dividends on Common Shares	*(Note 12)*	**-**	**-**	**(494)**	**-**	**(494)**
Common Shares Issued Under Dividend Reinvestment Plan	*(Note 12)*	**93**	**-**	**-**	**-**	**93**
Other Comprehensive Income (Loss)	*(Note 13)*	**-**	**-**	**-**	**14**	**14**
Balance, December 31, 2013		**$ 2,445**	**$ 15**	**$ 2,003**	**$ 684**	**$ 5,147**

Twelve Months Ended December 31, 2012 ($ millions)		Share Capital	Paid in Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2011		$ 2,354	$ 5	$ 5,643	$ 576	$ 8,578
Share-Based Compensation	*(Note 15)*	-	5	-	-	5
Net Earnings (Loss)		-	-	(2,794)	-	(2,794)
Dividends on Common Shares	*(Note 12)*	-	-	(588)	-	(588)
Other Comprehensive Income (Loss)	*(Note 13)*	-	-	-	94	94
Balance, December 31, 2012		$ 2,354	$ 10	$ 2,261	$ 670	$ 5,295

See accompanying Notes to Condensed Consolidated Financial Statements

Condensed Consolidated Statement of Cash Flows *(unaudited)*

($ millions)		Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Twelve Months Ended December 31, 2013	Twelve Months Ended December 31, 2012
Operating Activities					
Net earnings (loss)		**$ (251)**	$ (80)	**$ 236**	$ (2,794)
Depreciation, depletion and amortization		**388**	445	**1,565**	1,956
Impairments	*(Note 8)*	**-**	487	**21**	4,695
Accretion of asset retirement obligation	*(Note 11)*	**13**	13	**53**	53
Deferred income taxes	*(Note 7)*	**27**	(231)	**(57)**	(1,837)
Unrealized (gain) loss on risk management	*(Note 18)*	**301**	114	**345**	1,465
Unrealized foreign exchange (gain) loss	*(Note 6)*	**147**	58	**330**	(112)
Other		**41**	(10)	**55**	82
Net change in other assets and liabilities		**(21)**	(23)	**(80)**	(78)
Net change in non-cash working capital		**(183)**	(56)	**(179)**	(323)
Cash From (Used in) Operating Activities		**462**	717	**2,289**	3,107
Investing Activities					
Capital expenditures	*(Note 3)*	**(717)**	(780)	**(2,712)**	(3,476)
Acquisitions	*(Note 4)*	**(23)**	(18)	**(184)**	(379)
Proceeds from divestitures	*(Note 4)*	**95**	1,345	**705**	4,043
Cash in reserve		**24**	4	**44**	415
Net change in investments and other		**65**	31	**252**	(242)
Cash From (Used in) Investing Activities		**(556)**	582	**(1,895)**	361
Financing Activities					
Issuance of revolving long-term debt		**-**	-	**-**	1,721
Repayment of revolving long-term debt		**-**	-	**-**	(1,724)
Repayment of long-term debt	*(Note 9)*	**(500)**	-	**(500)**	(503)
Dividends on common shares	*(Note 12)*	**(39)**	(147)	**(401)**	(588)
Capital lease payments		**(5)**	(3)	**(8)**	(17)
Cash From (Used in) Financing Activities		**(544)**	(150)	**(909)**	(1,111)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(54)**	(9)	**(98)**	22
Increase (Decrease) in Cash and Cash Equivalents		**(692)**	1,140	**(613)**	2,379
Cash and Cash Equivalents, Beginning of Period		**3,258**	2,039	**3,179**	800
Cash and Cash Equivalents, End of Period		**$ 2,566**	$ 3,179	**$ 2,566**	$ 3,179
Cash, End of Period		**$ 161**	$ 92	**$ 161**	$ 92
Cash Equivalents, End of Period		**2,405**	3,087	**2,405**	3,087
Cash and Cash Equivalents, End of Period		**$ 2,566**	$ 3,179	**$ 2,566**	$ 3,179

See accompanying Notes to Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

1. Basis of Presentation

Encana Corporation and its subsidiaries ("Encana" or "the Company") are in the business of the exploration for, the development of, and the production and marketing of natural gas, oil and natural gas liquids ("NGLs"). The term liquids is used to represent Encana's oil, NGLs and condensate.

The interim Condensed Consolidated Financial Statements include the accounts of Encana and are presented in accordance with accounting principles generally accepted in the United States ("U.S. GAAP").

The interim Condensed Consolidated Financial Statements have been prepared following the same accounting policies and methods of computation as the annual audited Consolidated Financial Statements for the year ended December 31, 2012, except as noted below in Note 2. The disclosures provided below are incremental to those included with the annual audited Consolidated Financial Statements. Certain information and disclosures normally required to be included in the notes to the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, the interim Condensed Consolidated Financial Statements should be read in conjunction with the annual audited Consolidated Financial Statements and the notes thereto for the year ended December 31, 2012.

These unaudited interim Condensed Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

2. Recent Accounting Pronouncements

Changes in Accounting Policies and Practices

On January 1, 2013, Encana adopted the following accounting standards updates issued by the Financial Accounting Standards Board ("FASB"), which have not had a material impact on the Company's interim Condensed Consolidated Financial Statements:

- Accounting Standards Update 2011-11, “Disclosures about Offsetting Assets and Liabilities”, and Accounting Standards Update 2013-01, “Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities”, require disclosure of both gross and net information about certain financial instruments eligible for offset in the balance sheet and certain financial instruments subject to master netting arrangements. The amendments have been applied retrospectively.

- Accounting Standards Update 2013-02, “Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income”, requires enhanced disclosures about amounts reclassified out of accumulated other comprehensive income. The amendments have been applied prospectively.

New Standards Issued Not Yet Adopted

As of January 1, 2014, Encana will be required to adopt the following accounting standards updates issued by the FASB, which are not expected to have a material impact on the Company’s Consolidated Financial Statements:

- Accounting Standards Update 2013-04, “Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date”, clarifies guidance for the recognition, measurement and disclosure of liabilities resulting from joint and several liability arrangements. The amendments will be applied retrospectively.

- Accounting Standards Update 2013-05, “Parent’s Accounting for the Cumulative Translation Adjustment upon Derecognition of Certain Subsidiaries or Groups of Assets within a Foreign Entity or of an Investment in a Foreign Entity”, clarifies the applicable guidance for certain transactions that result in the release of the cumulative translation adjustment into net earnings. The amendments will be applied prospectively.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

2. Recent Accounting Pronouncements (continued)

New Standards Issued Not Yet Adopted (continued)

- 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", clarifies that a liability related to an unrecognized tax benefit or portions thereof should be presented as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss or a tax credit carryforward, except under specific situations. The amendments will be applied prospectively.

3. Segmented Information

Encana's reportable segments are determined based on the Company's operations and geographic locations as follows:

- **Canadian Division** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within the Canadian cost centre.

- **USA Division** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within the U.S. cost centre.

- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canadian and USA Divisions. Market optimization activities include third party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment. Market Optimization sells substantially all of the Company's upstream production to third party customers. Transactions between segments are based on market values and are eliminated on consolidation.

Corporate and Other mainly includes unrealized gains or losses recorded on derivative financial instruments. Once the instruments are settled, the realized gains and losses are recorded in the reporting segment to which the derivative instrument relates.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Results of Operations (For the three months ended December 31)

Segment and Geographic Information

	Canadian Division		USA Division		Market Optimization	
	2013	2012	**2013**	2012	**2013**	2012
Revenues, Net of Royalties	**$ 845**	$ 736	**$ 691**	$ 857	**$ 155**	$ 99
Expenses						
Production and mineral taxes	**4**	2	**33**	34	**-**	-
Transportation and processing	**225**	160	**175**	162	**-**	-
Operating	**90**	81	**108**	87	**12**	10
Purchased product	**-**	-	**-**	-	**138**	84
	526	493	**375**	574	**5**	5
Depreciation, depletion and amortization	**156**	176	**195**	238	**3**	3
Impairments	**-**	-	**-**	456	**-**	-
	$ 370	$ 317	**$ 180**	$ (120)	**$ 2**	$ 2

	Corporate & Other		Consolidated	
	2013	2012	**2013**	2012
Revenues, Net of Royalties	**$ (268)**	$ (87)	**$ 1,423**	$ 1,605
Expenses				
Production and mineral taxes	**-**	-	**37**	36
Transportation and processing	**5**	(4)	**405**	318
Operating	**11**	5	**221**	183
Purchased product	**-**	-	**138**	84
	(284)	(88)	**622**	984
Depreciation, depletion and amortization	**34**	28	**388**	445
Impairments	**-**	31	**-**	487
	$ (318)	$ (147)	**234**	52
Accretion of asset retirement obligation			**13**	13
Administrative			**167**	93
Interest			**139**	134
Foreign exchange (gain) loss, net			**160**	58
Other			**4**	3
			483	301
Net Earnings (Loss) Before Income Tax			**(249)**	(249)
Income tax expense (recovery)			**2**	(169)
Net Earnings (Loss)			**$ (251)**	$ (80)

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2013	2012	**2013**	2012	**2013**	2012
Revenues, Net of Royalties	**$ 1,466**	$ 1,283	**$ (1,311)**	$ (1,184)	**$ 155**	$ 99
Expenses						
Transportation and processing	**131**	132	**(131)**	(132)	**-**	-
Operating	**20**	21	**(8)**	(11)	**12**	10
Purchased product	**1,306**	1,112	**(1,168)**	(1,028)	**138**	84
Operating Cash Flow	**$ 9**	$ 18	**$ (4)**	$ (13)	**$ 5**	$ 5

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Results of Operations (For the twelve months ended December 31)

Segment and Geographic Information

	Canadian Division		USA Division		Market Optimization	
	2013	2012	**2013**	2012	**2013**	2012
Revenues, Net of Royalties	**$ 2,824**	$ 2,760	**$ 2,763**	$ 3,365	**$ 512**	$ 419
Expenses						
Production and mineral taxes	**15**	9	**119**	96	**-**	-
Transportation and processing	**756**	555	**722**	652	**-**	-
Operating	**372**	352	**411**	377	**38**	48
Purchased product	**-**	-	**-**	-	**441**	349
	1,681	1,844	**1,511**	2,240	**33**	22
Depreciation, depletion and amortization	**601**	748	**818**	1,102	**12**	12
Impairments	**-**	1,822	**-**	2,842	**-**	-
	$ 1,080	$ (726)	**$ 693**	$ (1,704)	**$ 21**	$ 10

	Corporate & Other		Consolidated	
	2013	2012	**2013**	2012
Revenues, Net of Royalties	**$ (241)**	$ (1,384)	**$ 5,858**	$ 5,160
Expenses				
Production and mineral taxes	**-**	-	**134**	105
Transportation and processing	**(2)**	24	**1,476**	1,231
Operating	**38**	17	**859**	794
Purchased product	**-**	-	**441**	349
	(277)	(1,425)	**2,948**	2,681
Depreciation, depletion and amortization	**134**	94	**1,565**	1,956
Impairments	**21**	31	**21**	4,695
	$ (432)	$ (1,550)	**1,362**	(3,970)
Accretion of asset retirement obligation			**53**	53
Administrative			**439**	392
Interest			**563**	522
Foreign exchange (gain) loss, net			**325**	(107)
Other			**(6)**	1
			1,374	861
Net Earnings (Loss) Before Income Tax			**(12)**	(4,831)
Income tax expense (recovery)			**(248)**	(2,037)
Net Earnings (Loss)			**$ 236**	$ (2,794)

Intersegment Information

	Market Optimization					
	Marketing Sales		Upstream Eliminations		Total	
	2013	2012	**2013**	2012	**2013**	2012
Revenues, Net of Royalties	**$ 5,662**	$ 4,260	**$ (5,150)**	$ (3,841)	**$ 512**	$ 419
Expenses						
Transportation and processing	**516**	528	**(516)**	(528)	**-**	-
Operating	**75**	84	**(37)**	(36)	**38**	48
Purchased product	**4,993**	3,593	**(4,552)**	(3,244)	**441**	349
Operating Cash Flow	**$ 78**	$ 55	**$ (45)**	$ (33)	**$ 33**	$ 22

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

3. Segmented Information (continued)

Capital Expenditures

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Canadian Division	**$ 354**	$ 373	**$ 1,365**	$ 1,567
USA Division	**343**	352	**1,283**	1,727
Market Optimization	**1**	-	**3**	7
Corporate & Other	**19**	55	**61**	175
	$ 717	$ 780	**$ 2,712**	$ 3,476

Goodwill, Property, Plant and Equipment and Total Assets by Segment

	Goodwill As at		Property, Plant and Equipment As at		Total Assets As at	
	December 31, 2013	December 31, 2012	**December 31, 2013**	December 31, 2012	**December 31, 2013**	December 31, 2012
Canadian Division	**$ 1,171**	$ 1,252	**$ 2,728**	$ 2,960	**$ 4,452**	$ 4,748
USA Division	**473**	473	**5,127**	4,405	**6,350**	5,664
Market Optimization	**-**	-	**91**	106	**161**	161
Corporate & Other	**-**	-	**2,089**	2,280	**6,685**	8,127
	$ 1,644	$ 1,725	**$ 10,035**	$ 9,751	**$ 17,648**	$ 18,700

4. Acquisitions and Divestitures

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Acquisitions				
Canadian Division	**$ 11**	$ 8	**$ 28**	$ 139
USA Division	**12**	10	**156**	240
Total Acquisitions	**23**	18	**184**	379
Divestitures				
Canadian Division	**(93)**	(1,265)	**(685)**	(3,770)
USA Division	**(2)**	(80)	**(18)**	(271)
Corporate & Other	**-**	-	**(2)**	(2)
Total Divestitures	**(95)**	(1,345)	**(705)**	(4,043)
Net Acquisitions & (Divestitures)	**$ (72)**	$ (1,327)	**$ (521)**	$ (3,664)

Acquisitions

For the three and twelve months ended December 31, 2013, acquisitions in the Canadian and USA Divisions totaled $23 million and $184 million, respectively (2012 - $18 million and $379 million, respectively), which primarily included land and property purchases with oil and liquids rich natural gas production potential.

Divestitures

For the three and twelve months ended December 31, 2013, divestitures in the Canadian Division were $93 million and $685 million, respectively. During the twelve months ended December 31, 2013, divestitures included the sale of the Company's Jean Marie natural gas assets in the Greater Sierra resource play in northeast British Columbia and other assets.

For the twelve months ended December 31, 2012, divestitures in the Canadian Division were $3,770 million, which primarily included C$1.18 billion received from a PetroChina Company Limited subsidiary, C$1.45 billion received from a Mitsubishi Corporation subsidiary, C$100 million received from a Toyota Tsusho Corporation subsidiary and approximately C$920 million received from the sale of two natural gas processing plants.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

4. Acquisitions and Divestitures (continued)

Divestitures (continued)

For the three and twelve months ended December 31, 2013, divestitures in the USA Division were $2 million and $18 million, respectively. For the twelve months ended December 31, 2012, divestitures in the USA Division were $271 million, which primarily included proceeds of $114 million received from the remainder of the North Texas asset sale.

Amounts received from these transactions have been deducted from the respective Canadian and U.S. full cost pools.

5. Interest

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Interest Expense on:				
Debt	**$ 112**	$ 119	**$ 460**	$ 474
The Bow office building	**20**	9	**76**	16
Capital leases and other	**7**	6	**27**	32
	$ 139	$ 134	**$ 563**	$ 522

Interest on The Bow office building and capital leases and other were previously reported together in other interest expense in 2012.

6. Foreign Exchange (Gain) Loss, Net

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Unrealized Foreign Exchange (Gain) Loss on:				
Translation of U.S. dollar debt issued from Canada	**$ 156**	$ 69	**$ 349**	$ (131)
Translation of U.S. dollar risk management contracts issued from Canada	**(9)**	(11)	**(19)**	19
	147	58	**330**	(112)
Foreign Exchange on Intercompany Transactions	**-**	11	**-**	4
Other Monetary Revaluations and Settlements	**13**	(11)	**(5)**	1
	$ 160	$ 58	**$ 325**	$ (107)

7. Income Taxes

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Current Tax				
Canada	**$ 19**	$ 58	**$ (152)**	$ (219)
United States	**(50)**	(1)	**(64)**	(25)
Other Countries	**6**	5	**25**	44
Total Current Tax Expense (Recovery)	**(25)**	62	**(191)**	(200)
Deferred Tax				
Canada	**(151)**	(72)	**(106)**	(902)
United States	**97**	110	**52**	(935)
Other Countries	**81**	(269)	**(3)**	-
Total Deferred Tax Expense (Recovery)	**27**	(231)	**(57)**	(1,837)
	$ 2	$ (169)	**$ (248)**	$ (2,037)

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

8. Property, Plant and Equipment, Net

	As at December 31, 2013			As at December 31, 2012		
	Cost	Accumulated DD&A [(1)]	Net	Cost	Accumulated DD&A [(1)]	Net
Canadian Division						
Proved properties	$ 25,003	$ (23,012)	$ 1,991	$ 26,024	$ (23,962)	$ 2,062
Unproved properties	598	-	598	716	-	716
Other	139	-	139	182	-	182
	25,740	(23,012)	2,728	26,922	(23,962)	2,960
USA Division						
Proved properties	26,529	(22,074)	4,455	24,825	(21,236)	3,589
Unproved properties	470	-	470	579	-	579
Other	202	-	202	237	-	237
	27,201	(22,074)	5,127	25,641	(21,236)	4,405
Market Optimization	223	(132)	91	235	(129)	106
Corporate & Other	2,655	(566)	2,089	2,829	(549)	2,280
	$ 55,819	$ (45,784)	$ 10,035	$ 55,627	$ (45,876)	$ 9,751

(1) Depreciation, depletion and amortization.

The Canadian Division and USA Division property, plant and equipment include internal costs directly related to exploration, development and construction activities of $372 million which have been capitalized during the twelve months ended December 31, 2013 (2012 - $471 million). Included in Corporate and Other are $71 million (2012 - $104 million) of international property costs, which have been fully impaired.

For the three months ended December 31, 2012, the Company recognized a ceiling test impairment of nil in the Canadian cost centre and $456 million in the U.S. cost centre. For the twelve months ended December 31, 2012, the Company recognized a ceiling test impairment of $1,822 million in the Canadian cost centre and $2,842 million in the U.S. cost centre. The impairments resulted primarily from the decline in the 12-month average trailing natural gas prices which reduced proved reserves volumes and values.

The 12-month average trailing prices used in the ceiling test calculations reflect benchmark prices adjusted for basis differentials to determine local reference prices, transportation costs and tariffs, heat content and quality. At December 31, 2013, the 12-month average trailing prices used in the Canadian cost centre ceiling test calculation were C$3.14/MMBtu for AECO (2012 - C$2.35/MMBtu) and C$93.44/bbl for Edmonton Light Sweet (2012 - C$87.42/bbl). At December 31, 2013, the 12-month average trailing prices used in the U.S. cost centre ceiling test calculation were $3.67/MMBtu for Henry Hub (2012 - $2.76/MMBtu) and $96.94/bbl for WTI (2012 - $94.71/bbl).

Capital Lease Arrangements

The Company has several lease arrangements that are accounted for as capital leases, including an office building, equipment and an offshore production platform.

In December 2013, Encana commenced commercial operations at its Deep Panuke facility located offshore Nova Scotia following successful completion of the Production Field Centre ("PFC") and issuance of the Production Acceptance Notice. As at December 31, 2013, Canadian Division property, plant and equipment and total assets include the PFC, which is under a capital lease totaling $536 million. As at December 31, 2012, $612 million in accumulated costs related to the PFC were recorded as an asset under construction.

Other Arrangement

As at December 31, 2013, Corporate and Other property, plant and equipment and total assets include Encana's accumulated costs to date of $1,617 million (2012 - $1,668 million) related to The Bow office building. In 2012, Encana assumed partial occupancy of The Bow office premises and commenced payments to the third party developer under a 25-year lease agreement. As of March 31, 2013, Encana had assumed full occupancy of the building. The Bow asset is being depreciated over the 60-year estimated life of the building. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized as disclosed in Note 10.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

8. Property, Plant and Equipment, Net (continued)

Liabilities for the capital lease arrangements and The Bow office building are included in other liabilities and provisions in the Condensed Consolidated Balance Sheet and are disclosed in Note 10.

9. Long-Term Debt

	C$ Principal Amount	As at December 31, 2013	As at December 31, 2012
Canadian Dollar Denominated Debt			
5.80% due January 18, 2018	$ 750	$ 705	$ 754
	$ 750	705	754
U.S. Dollar Denominated Debt			
4.75% due October 15, 2013		-	500
5.80% due May 1, 2014		1,000	1,000
5.90% due December 1, 2017		700	700
6.50% due May 15, 2019		500	500
3.90% due November 15, 2021		600	600
8.125% due September 15, 2030		300	300
7.20% due November 1, 2031		350	350
7.375% due November 1, 2031		500	500
6.50% due August 15, 2034		750	750
6.625% due August 15, 2037		500	500
6.50% due February 1, 2038		800	800
5.15% due November 15, 2041		400	400
		6,400	6,900
Total Principal		7,105	7,654
Increase in Value of Debt Acquired		40	46
Debt Discounts		(21)	(25)
Current Portion of Long-Term Debt		(1,000)	(500)
		$ 6,124	$ 7,175

Long-term debt is accounted for at amortized cost using the effective interest method of amortization. As at December 31, 2013, total long-term debt had a carrying value of $7,124 million and a fair value of $7,805 million (2012 - $7,675 million carrying value and a fair value of $9,043 million). The estimated fair value of long-term borrowings is categorized within Level 2 of the fair value hierarchy and has been determined based on market information or by discounting future payments of interest and principal at interest rates expected to be available to the Company at period end.

10. Other Liabilities and Provisions

	As at December 31, 2013	As at December 31, 2012
The Bow Office Building (See Note 8)	$ 1,631	$ 1,674
Asset under Construction - Production Field Centre (See Note 8)	-	612
Capital Lease Obligations (See Note 8)	544	69
Unrecognized Tax Benefits	133	134
Pensions and Other Post-Employment Benefits	110	165
Other	102	18
	$ 2,520	$ 2,672

10. Other Liabilities and Provisions (continued)

The Bow Office Building

As described in Note 8, Encana has recognized the accumulated costs for The Bow office building as an asset with a related liability. In 2012, Encana commenced payments to the third party developer under a 25-year agreement. At the conclusion of the 25-year term, the remaining asset and corresponding liability are expected to be derecognized. Encana has also subleased part of The Bow office space to a subsidiary of Cenovus Energy Inc. ("Cenovus"). The total undiscounted future payments related to the lease agreement and the total undiscounted future amounts expected to be recovered from the Cenovus sublease are outlined below.

(undiscounted)	2014	2015	2016	2017	2018	Thereafter	Total
Expected future lease payments	$ 87	$ 87	$ 88	$ 89	$ 90	$ 1,893	**$ 2,334**
Sublease recoveries	$ (43)	$ (43)	$ (44)	$ (44)	$ (44)	$ (939)	**$ (1,157)**

Capital Lease Obligations

As described in Note 8, the PFC commenced commercial operations in December 2013. Accordingly, Encana derecognized the asset under construction and related liability and recorded the PFC as a capital lease asset with a corresponding capital lease obligation. Under the lease contract, Encana has a purchase option and the option to extend the lease for 12 one-year terms at fixed prices after the initial lease term expires in 2021. As a result, the lease contract qualifies as a variable interest and the related leasing entity qualifies as a variable interest entity ("VIE"). Encana is not the primary beneficiary of the VIE as the Company does not have the power to direct the activities that most significantly impact the VIE's economic performance. Encana is not required to provide any financial support or guarantees to the lease entity and its affiliates, other than the contractual payments under the lease and operating contracts.

The total expected future lease payments related to the Company's capital lease obligations are outlined below.

	2014	2015	2016	2017	2018	Thereafter	Total
Expected future lease payments	$ 106	$ 93	$ 93	$ 94	$ 94	$ 315	**$ 795**
Less amounts representing interest	40	32	28	25	20	40	**185**
Present value of expected future lease payments	$ 66	$ 61	$ 65	$ 69	$ 74	$ 275	**$ 610**

11. Asset Retirement Obligation

	As at December 31, 2013	As at December 31, 2012
Asset Retirement Obligation, Beginning of Year	**$ 969**	$ 921
Liabilities Incurred	**38**	43
Liabilities Settled	**(126)**	(90)
Change in Estimated Future Cash Outflows	**68**	28
Accretion Expense	**53**	53
Foreign Currency Translation	**(36)**	14
Asset Retirement Obligation, End of Year	**$ 966**	$ 969
Current Portion	**$ 66**	$ 33
Long-Term Portion	**900**	936
	$ 966	$ 969

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. Share Capital

Authorized

The Company is authorized to issue an unlimited number of no par value common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares.

Issued and Outstanding

	As at December 31, 2013			As at December 31, 2012		
	Number (millions)		Amount	Number (millions)		Amount
Common Shares Outstanding, Beginning of Year	736.3	$	2,354	736.3	$	2,354
Common Shares Cancelled	(0.8)		(2)	-		-
Common Shares Issued Under Dividend Reinvestment Plan	5.4		93	-		-
Common Shares Outstanding, End of Year	740.9	$	2,445	736.3	$	2,354

During the twelve months ended December 31, 2013, Encana cancelled 767,327 common shares reserved for issuance to shareholders upon exchange of predecessor companies' shares. In accordance with the terms of the merger agreement which formed Encana, shares which have remained unexchanged were extinguished. Accordingly, the weighted average book value of the common shares extinguished of $2 million has been transferred to paid in surplus.

During the three months ended December 31, 2013, Encana issued 707,721 common shares totaling $13 million under the Company's dividend reinvestment plan. During the twelve months ended December 31, 2013, Encana issued 5,385,845 common shares totaling $93 million under the Company's dividend reinvestment plan.

Dividends

During the three months ended December 31, 2013, Encana paid dividends of $0.07 per common share totaling $52 million (2012 - $0.20 per common share totaling $147 million). During the twelve months ended December 31, 2013, Encana paid dividends of $0.67 per common share totaling $494 million (2012 - $0.80 per common share totaling $588 million).

For the three and twelve months ended December 31, 2013, the dividends paid included $13 million and $93 million, respectively, in common shares as disclosed above, which were issued in lieu of cash dividends under the Company's dividend reinvestment plan (2012 - nil).

Earnings Per Common Share

The following table presents the computation of net earnings per common share:

	Three Months Ended December 31,				Twelve Months Ended December 31,			
(millions, except per share amounts)		2013		2012		2013		2012
Net Earnings (Loss)	$	(251)	$	(80)	$	236	$	(2,794)
Number of Common Shares:								
Weighted average common shares outstanding - Basic		740.4		736.3		737.7		736.3
Effect of dilutive securities		-		-		-		-
Weighted average common shares outstanding - Diluted		740.4		736.3		737.7		736.3
Net Earnings (Loss) per Common Share								
Basic	$	(0.34)	$	(0.11)	$	0.32	$	(3.79)
Diluted	$	(0.34)	$	(0.11)	$	0.32	$	(3.79)

Encana Stock Option Plan

Encana has share-based compensation plans that allow employees to purchase common shares of the Company. Option exercise prices are not less than the market value of the common shares on the date the options are granted. All options outstanding as at December 31, 2013 have associated Tandem Stock Appreciation Rights ("TSARs") attached. In lieu of exercising the option, the associated TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Encana's common shares at the time of the exercise over the original grant price.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

12. Share Capital (continued)

Encana Stock Option Plan (continued)

In addition, certain stock options granted are performance-based whereby vesting is also subject to Encana attaining prescribed performance relative to predetermined key measures. Historically, most holders of options with TSARs have elected to exercise their stock options as a Stock Appreciation Right ("SAR") in exchange for a cash payment. As a result, Encana does not consider outstanding TSARs to be potentially dilutive securities.

Encana Restricted Share Units ("RSUs")

Encana has a share-based compensation plan whereby eligible employees are granted RSUs. An RSU is a conditional grant to receive an Encana common share, or the cash equivalent, as determined by Encana, upon vesting of the RSUs and in accordance with the terms of the RSU Plan and Grant Agreement. The Company intends to settle vested RSUs in cash on the vesting date. As a result, Encana does not consider RSUs to be potentially dilutive securities.

Encana Share Units Held by Cenovus Employees

On November 30, 2009, Encana completed a corporate reorganization to split into two independent publicly traded energy companies - Encana Corporation and Cenovus Energy Inc. (the "Split Transaction"). In conjunction with the Split Transaction, each holder of Encana share units disposed of their right in exchange for the grant of new Encana share units and Cenovus share units. Share units include TSARs, Performance TSARs, SARs, and Performance SARs. The terms and conditions of the share units are similar to the terms and conditions of the original share units.

With respect to the Encana share units held by Cenovus employees and the Cenovus share units held by Encana employees, both Encana and Cenovus have agreed to reimburse each other for share units exercised for cash by their respective employees. Accordingly, for Encana share units held by Cenovus employees, Encana has recorded a payable to Cenovus employees and a receivable due from Cenovus. The payable to Cenovus employees and the receivable due from Cenovus are based on the fair value of the Encana share units determined using the Black-Scholes-Merton model (See Notes 15 and 17). There is no impact on Encana's net earnings for the share units held by Cenovus employees. TSARs and Performance TSARs held by Cenovus employees will expire by December 2014.

Cenovus employees may exercise Encana TSARs and Encana Performance TSARs in exchange for Encana common shares. As at December 31, 2013, there were 1.5 million Encana TSARs and 2.4 million Encana Performance TSARs with a weighted average exercise price of C$29.09 and C$29.04, respectively, held by Cenovus employees, which were outstanding and exercisable.

13. Accumulated Other Comprehensive Income

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Foreign Currency Translation Adjustment				
Balance, Beginning of Period	**$ 720**	$ 744	**$ 739**	$ 658
Current Period Change in Foreign Currency Translation Adjustment	**(27)**	(5)	**(46)**	81
Balance, End of Period	**$ 693**	$ 739	**$ 693**	$ 739
Pension and Other Post-Employment Benefit Plans				
Balance, Beginning of Period	**$ (61)**	$ (74)	**$ (69)**	$ (82)
Net Actuarial Gains and (Losses) and Plan Amendment (See Note 16)	**65**	3	**65**	3
Income Taxes	**(17)**	(1)	**(17)**	(1)
Reclassification of Net Actuarial (Gains) and Losses to Net Earnings (See Note 16)	**-**	4	**11**	15
Income Taxes	**-**	(1)	**(3)**	(4)
Settlement & Curtailment in Defined Benefit Plan Expense (See Note 16)	**6**	-	**6**	-
Income Taxes	**(2)**	-	**(2)**	-
Balance, End of Period	**$ (9)**	$ (69)	**$ (9)**	$ (69)
Total Accumulated Other Comprehensive Income	**$ 684**	$ 670	**$ 684**	$ 670

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

14. Restructuring Charges

In November 2013, Encana announced its plans to align the organizational structure in support of the new strategy and its intention to reduce the Company's workforce by approximately 20 percent. In conjunction with the restructuring, Encana also announced its plan to close the Company's office, located in Plano Texas, in 2014. For the twelve months ended December 31, 2013, Encana has incurred restructuring charges totaling $88 million relating primarily to severance costs, which are included in administrative expenses in the Company's Condensed Consolidated Statement of Earnings. Of the $88 million in restructuring charges incurred to date, $65 million remains accrued as at December 31, 2013. Total charges associated with the restructuring are anticipated to be complete in 2015 and are expected to be approximately $130 million before tax.

15. Compensation Plans

Encana has a number of compensation arrangements under which the Company awards various types of long-term incentive grants to eligible employees. These primarily include TSARs, Performance TSARs, SARs, Performance SARs, Performance Share Units ("PSUs"), Deferred Share Units ("DSUs") and RSUs. These compensation arrangements are share-based.

Encana accounts for TSARs, Performance TSARs, SARs, Performance SARs, PSUs and RSUs held by Encana employees as cash-settled share-based payment transactions and accordingly, accrues compensation costs over the vesting period based on the fair value of the rights determined using the Black-Scholes-Merton and other fair value models.

As at December 31, 2013, the following weighted average assumptions were used to determine the fair value of the share units held by Encana employees:

	Encana US$ Share Units	Encana C$ Share Units	Cenovus C$ Share Units
Risk Free Interest Rate	1.09%	1.09%	1.09%
Dividend Yield	1.55%	1.50%	3.18%
Expected Volatility Rate	33.20%	30.42%	27.75%
Expected Term	1.8 yrs	1.7 yrs	0.1 yrs
Market Share Price	US$18.05	C$19.18	C$30.40

The Company has recognized the following share-based compensation costs:

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Compensation Costs of Transactions Classified as Cash-Settled	**$ 36**	$ (36)	**$ 63**	$ 42
Compensation Costs of Transactions Classified as Equity-Settled [(1)]	**(1)**	3	**3**	5
Total Share-Based Compensation Costs	**35**	(33)	**66**	47
Less: Total Share-Based Compensation Costs Capitalized	**(13)**	9	**(22)**	(14)
Total Share-Based Compensation Expense	**$ 22**	$ (24)	**$ 44**	$ 33
Recognized on the Condensed Consolidated Statement of Earnings in:				
Operating expense	**$ 10**	$ (15)	**$ 18**	$ 13
Administrative expense	**12**	(9)	**26**	20
	$ 22	$ (24)	**$ 44**	$ 33

(1) RSUs may be settled in cash or equity as determined by Encana. The Company's decision to cash settle RSUs was made subsequent to the original grant date.

As at December 31, 2013, the liability for share-based payment transactions totaled $169 million, of which $111 million is recognized in accounts payable and accrued liabilities.

	As at December 31, 2013	As at December 31, 2012
Liability for Unvested Cash-Settled Share-Based Payment Transactions	**$ 121**	$ 85
Liability for Vested Cash-Settled Share-Based Payment Transactions	**48**	71
Liability for Cash-Settled Share-Based Payment Transactions	**$ 169**	$ 156

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

15. Compensation Plans (continued)

The following units were granted during the twelve months ended December 31, 2013. The TSARs and SARs were granted at the market price of Encana's common shares on the grant date.

Twelve Months Ended December 31, 2013 (thousands of units)	
TSARs	10,644
SARs	5,048
PSUs	1,102
DSUs	184
RSUs	6,675

16. Pension and Other Post-Employment Benefits

The Company has recognized total benefit plans expense which includes pension benefits and other post-employment benefits ("OPEB") for the twelve months ended December 31 as follows:

	Pension Benefits		OPEB		Total	
	2013	2012	**2013**	2012	**2013**	2012
Defined Benefit Plan Expense	**$ 21**	$ 6	**$ 11**	$ 18	**$ 32**	$ 24
Defined Contribution Plan Expense	**43**	44	**-**	-	**43**	44
Total Benefit Plans Expense	**$ 64**	$ 50	**$ 11**	$ 18	**$ 75**	$ 68

Of the total benefit plans expense, $60 million (2012 - $55 million) was included in operating expense and $15 million (2012 - $13 million) was included in administrative expense.

The defined periodic pension and OPEB expense for the twelve months ended December 31 is as follows:

	Pension Benefits		OPEB		Total	
	2013	2012	**2013**	2012	**2013**	2012
Current service costs	**$ 4**	$ 5	**$ 12**	$ 14	**$ 16**	$ 19
Interest cost	**12**	14	**4**	4	**16**	18
Expected return on plan assets	**(16)**	(28)	**-**	-	**(16)**	(28)
Amounts reclassified from accumulated other comprehensive income:						
Amortization of net actuarial (gains) and losses	**11**	15	**-**	-	**11**	15
Settlement	**5**	-	**-**	-	**5**	-
Curtailment	**1**	-	**(5)**	-	**(4)**	-
Special termination benefits	**4**	-	**-**	-	**4**	-
Total Defined Benefit Plan Expense	**$ 21**	$ 6	**$ 11**	$ 18	**$ 32**	$ 24

The amounts recognized in other comprehensive income for the twelve months ended December 31 are as follows:

	Pension Benefits		OPEB		Total	
	2013	2012	**2013**	2012	**2013**	2012
Net actuarial (gains) losses	**$ (46)**	$ 2	**$ (6)**	$ (5)	**$ (52)**	$ (3)
Plan amendment	**-**	-	**(13)**	-	**(13)**	-
Amortization of net actuarial gains and losses	**(11)**	(15)	**-**	-	**(11)**	(15)
Settlement	**(5)**	-	**-**	-	**(5)**	-
Curtailment	**(1)**	-	**-**	-	**(1)**	-
Total Amounts Recognized in Other Comprehensive (Income) Loss, Before Tax	**$ (63)**	$ (13)	**$ (19)**	$ (5)	**$ (82)**	$ (18)
Total Amounts Recognized in Other Comprehensive (Income) Loss, After Tax	**$ (46)**	$ (9)	**$ (14)**	$ (4)	**$ (60)**	$ (13)

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Fair Value Measurements

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, and accounts payable and accrued liabilities approximate their carrying amounts due to the short-term maturity of those instruments except for the amounts associated with share units issued as part of the Split Transaction, as disclosed below. The fair value of cash in reserve approximates its carrying amount due to the nature of the instrument held.

Recurring fair-value measurements are performed for risk management assets and liabilities and for share units resulting from the Split Transaction, which are discussed further in Notes 18 and 12, respectively. These items are carried at fair value in the Condensed Consolidated Balance Sheet and are classified within the three levels of the fair value hierarchy in the tables below. There have been no transfers between the hierarchy levels during the period.

As at December 31, 2013	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [4]	Carrying Amount
Risk Management						
Risk Management Assets						
Current	**$ -**	**$ 71**	**$ -**	**$ 71**	**$ (15)**	**$ 56**
Long-term	**-**	**204**	**-**	**204**	**-**	**204**
Risk Management Liabilities						
Current	**-**	**38**	**2**	**40**	**(15)**	**25**
Long-term	**-**	**-**	**5**	**5**	**-**	**5**
Share Units Resulting from the Split Transaction						
Encana Share Units Held by Cenovus Employees						
Accounts receivable and accrued revenues [1]	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Accounts payable and accrued liabilities [2]	**-**	**-**	**-**	**-**	**-**	**-**
Cenovus Share Units Held by Encana Employees						
Accounts payable and accrued liabilities [3]	**-**	**-**	**8**	**8**	**-**	**8**

As at December 31, 2012	Level 1 Quoted Prices in Active Markets	Level 2 Other Observable Inputs	Level 3 Significant Unobservable Inputs	Total Fair Value	Netting [4]	Carrying Amount
Risk Management						
Risk Management Assets						
Current	$ 2	$ 505	$ -	$ 507	$ (28)	$ 479
Long-term	-	112	-	112	(1)	111
Risk Management Liabilities						
Current	-	25	8	33	(28)	5
Long-term	-	7	4	11	(1)	10
Share Units Resulting from the Split Transaction						
Encana Share Units Held by Cenovus Employees						
Accounts receivable and accrued revenues [1]	$ -	$ -	$ 1	$ 1	$ -	$ 1
Accounts payable and accrued liabilities [2]	-	-	1	1	-	1
Cenovus Share Units Held by Encana Employees						
Accounts payable and accrued liabilities [3]	-	-	36	36	-	36

(1) Receivable from Cenovus.

(2) Payable to Cenovus employees.

(3) Payable to Cenovus.

(4) Netting to offset derivative assets and liabilities where the legal right and intention to offset exists, or where counterparty master netting arrangements contain provisions for net settlement.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

17. Fair Value Measurements (continued)

The Company's Level 1 and Level 2 risk management assets and liabilities consist of commodity fixed price contracts and basis swaps with terms to 2016. The fair values of these contracts are based on a market approach and are estimated using inputs which are either directly or indirectly observable at the reporting date, such as exchange and other published prices, broker quotes and observable trading activity.

Level 3 Fair Value Measurements

As at December 31, 2013, the Company's Level 3 risk management assets and liabilities consist of power purchase contracts with terms to 2017. The fair values of the power purchase contracts are based on the income approach and are modelled internally using observable and unobservable inputs such as forward power prices in less active markets. The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness.

Changes in amounts related to risk management assets and liabilities are recognized in revenues and transportation and processing expense according to their purpose. Changes in amounts related to share units resulting from the Split Transaction are recognized in operating expense, administrative expense and capitalized within property, plant and equipment as described in Note 15.

A summary of changes in Level 3 fair value measurements for the twelve months ended December 31 is presented below:

	Risk Management		Share Units Resulting from Split Transaction	
	2013	2012	**2013**	2012
Balance, Beginning of Year	**$ (12)**	$ 18	**$ (36)**	$ (83)
Total gains (losses)	**3**	(18)	**16**	4
Purchases, issuances and settlements:				
Purchases	**-**	-	**-**	-
Settlements	**2**	(12)	**12**	43
Transfers in and out of Level 3	**-**	-	**-**	-
Balance, End of Year	**$ (7)**	$ (12)	**$ (8)**	$ (36)
Change in unrealized gains (losses) related to assets and liabilities held at end of year	**$ (2)**	$ (21)	**$ 20**	$ (7)

Quantitative information about unobservable inputs used in Level 3 fair value measurements is presented below:

	Valuation Technique	Unobservable Input	**As at December 31, 2013**	As at December 31, 2012
Risk Management - Natural Gas Options	Option Model	Price volatility	**-**	0.3% - 28.3%
Risk Management - Power	Discounted Cash Flow	Forward prices ($/Megawatt Hour)	**$49.25 - $54.47**	$48.25 - $57.97
Share Units Resulting from the Split Transaction	Option Model	Cenovus share unit volatility	**27.75%**	30.18%

A five percentage point increase or decrease in natural gas price volatility would cause no decrease or increase (2012 - nil) to net risk management assets. A 10 percent increase or decrease in estimated forward power prices would cause a corresponding $7 million (2012 - $6 million) increase or decrease to net risk management assets. A five percentage point increase or decrease in Cenovus share unit estimated volatility would cause no increase or decrease (2012 - $2 million) to accounts payable and accrued liabilities.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. Financial Instruments and Risk Management

A) Financial Instruments

Encana's financial assets and liabilities are recognized in cash and cash equivalents, accounts receivable and accrued revenues, cash in reserve, accounts payable and accrued liabilities, risk management assets and liabilities and long-term debt.

B) Risk Management Assets and Liabilities

Risk management assets and liabilities arise from the use of derivative financial instruments and are measured at fair value. See Note 17 for a discussion of fair value measurements.

Unrealized Risk Management Position	**As at December 31, 2013**	As at December 31, 2012
Risk Management Asset		
Current	**$ 56**	$ 479
Long-term	**204**	111
	260	590
Risk Management Liability		
Current	**25**	5
Long-term	**5**	10
	30	15
Net Risk Management Asset	**$ 230**	$ 575

Commodity Price Positions as at December 31, 2013

	Notional Volumes		Term	Average Price		Fair Value
Natural Gas Contracts						
Fixed Price Contracts						
NYMEX Fixed Price	2,138	MMcf/d	2014	4.17	US$/Mcf	**$ (13)**
NYMEX Fixed Price	825	MMcf/d	2015	4.37	US$/Mcf	**65**
Basis Contracts [(1)]			2014-2016			**116**
Natural Gas Fair Value Position						**168**
Crude Oil Contracts						
Fixed Price Contracts						
WTI Fixed Price	9.5	Mbbls/d	2014	94.19	US$/bbl	**(5)**
Basis Contracts [(2)]			2014-2015			**74**
Crude Oil Fair Value Position						**69**
Power Purchase Contracts						
Fair Value Position						**(7)**
Total Fair Value Position						**$ 230**

(1) Encana has entered into swaps to protect against widening natural gas price differentials in Canada. These basis swaps are priced using differentials determined as a percentage of NYMEX.

(2) Encana has entered into swaps to protect against widening oil price differentials between Brent and WTI. These basis swaps are priced using fixed price differentials.

18. Financial Instruments and Risk Management (continued)

B) Risk Management Assets and Liabilities (continued)

Earnings Impact of Realized and Unrealized Gains (Losses) on Risk Management Positions

	Realized Gain (Loss)			
	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Revenues, Net of Royalties	**$ 175**	$ 419	**$ 544**	$ 2,149
Transportation and Processing	**(1)**	1	**-**	12
Gain (Loss) on Risk Management	**$ 174**	$ 420	**$ 544**	$ 2,161

	Unrealized Gain (Loss)			
	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2013	2012	**2013**	2012
Revenues, Net of Royalties	**$ (296)**	$ (118)	**$ (347)**	$ (1,441)
Transportation and Processing	**(5)**	4	**2**	(24)
Gain (Loss) on Risk Management	**$ (301)**	$ (114)	**$ (345)**	$ (1,465)

Reconciliation of Unrealized Risk Management Positions from January 1 to December 31

	2013		2012
	Fair Value	**Total Unrealized Gain (Loss)**	Total Unrealized Gain (Loss)
Fair Value of Contracts, Beginning of Year	**$ 575**		
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**199**	**$ 199**	$ 696
Fair Value of Contracts Realized During the Year	**(544)**	**(544)**	(2,161)
Fair Value of Contracts, End of Year	**$ 230**	**$ (345)**	$ (1,465)

C) Risks Associated with Financial Assets and Liabilities

The Company is exposed to financial risks including market risks (such as commodity prices, foreign exchange and interest rates), credit risk and liquidity risk. Future cash flows may fluctuate due to movement in market prices and the exposure to credit and liquidity risks.

Commodity Price Risk

Commodity price risk arises from the effect fluctuations in future commodity prices may have on future cash flows. To partially mitigate exposure to commodity price risk, the Company has entered into various derivative financial instruments. The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board. The Company's policy is to not use derivative financial instruments for speculative purposes.

Natural Gas - To partially mitigate natural gas commodity price risk, the Company uses contracts such as NYMEX-based swaps and options. Encana also enters into basis swaps to manage against widening price differentials between various production areas and various sales points.

Crude Oil - To help protect against widening crude oil price differentials between North American and world prices, the Company has entered into fixed price contracts and basis swaps.

Power - The Company has entered into Canadian dollar denominated derivative contracts to manage its electricity consumption costs.

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

18. Financial Instruments and Risk Management (continued)

C) Risks Associated with Financial Assets and Liabilities (continued)

Commodity Price Risk (continued)

The table below summarizes the sensitivity of the fair value of the Company's risk management positions to fluctuations in commodity prices, with all other variables held constant. The Company has used a 10 percent variability to assess the potential impact of commodity price changes. Fluctuations in commodity prices could have resulted in unrealized gains (losses) impacting pre-tax net earnings as at December 31 as follows:

	2013		2012	
	10% Price Increase	**10% Price Decrease**	10% Price Increase	10% Price Decrease
Natural gas price	**$ (441)**	**$ 441**	$ (446)	$ 446
Crude oil price	**(19)**	**19**	(20)	20
Power price	**7**	**(7)**	6	(6)

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of Board-approved credit policies governing the Company's credit portfolio including credit practices that limit transactions according to counterparties' credit quality. Mitigation strategies may include master netting arrangements, requesting collateral and/or transacting credit derivatives. The Company executes commodity derivative financial instruments under master agreements that have netting provisions that provide for offsetting payables against receivables. As at December 31, 2013, the Company had no significant collateral balances posted or received and there were no credit derivatives in place.

As at December 31, 2013, cash equivalents include high-grade, short-term securities, placed primarily with financial institutions and companies with strong investment grade ratings. Any foreign currency agreements entered into are with major financial institutions in Canada and the U.S. or with counterparties having investment grade credit ratings.

A substantial portion of the Company’s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2013, approximately 87 percent (2012 - 88 percent) of Encana's accounts receivable and financial derivative credit exposures were with investment grade counterparties.

As at December 31, 2013, Encana had four counterparties (2012 - two counterparties) whose net settlement position individually accounted for more than 10 percent of the fair value of the outstanding in-the-money net risk management contracts by counterparty. As at December 31, 2013, these counterparties accounted for 24 percent, 14 percent, 14 percent and 13 percent (2012 - 22 percent and 15 percent) of the fair value of the outstanding in-the-money net risk management contracts.

Liquidity Risk

Liquidity risk arises from the potential that the Company will encounter difficulties in meeting a demand to fund its financial liabilities as they come due. The Company manages liquidity risk using cash and debt management programs.

The Company has access to cash equivalents and a range of funding alternatives at competitive rates through committed revolving bank credit facilities and debt capital markets. In June 2013, the Company extended the maturity date of its existing revolving bank credit facilities and reduced the Canadian facility from C$4.0 billion to C$3.5 billion. As at December 31, 2013, the Company had available unused committed revolving bank credit facilities totaling $4.3 billion which include C$3.5 billion ($3.3 billion) on a revolving bank credit facility for Encana and $999 million on a revolving bank credit facility for a U.S. subsidiary. The facilities remain committed through June 2018.

Encana also has unused capacity under a shelf prospectus for up to $4.0 billion, or the equivalent in foreign currencies, the availability of which is dependent on market conditions, to issue up to $4.0 billion of debt securities in the U.S. The shelf prospectus expires in June 2014.

The Company believes it has sufficient funding through the use of these facilities to meet foreseeable borrowing requirements.

18. Financial Instruments and Risk Management (continued)

C) Risks Associated with Financial Assets and Liabilities (continued)

Liquidity Risk (continued)

The Company minimizes its liquidity risk by managing its capital structure. The Company's capital structure consists of shareholders' equity plus long-term debt, including the current portion. The Company's objectives when managing its capital structure are to maintain financial flexibility to preserve Encana's access to capital markets and its ability to meet financial obligations and to finance internally generated growth as well as potential acquisitions. To manage the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, issue new shares, issue new debt or repay existing debt.

The timing of expected cash outflows relating to financial liabilities is outlined in the table below:

	Less Than 1 Year	1 - 3 Years	4 - 5 Years	6 - 9 Years	Thereafter	Total
Accounts Payable and Accrued Liabilities	$ 1,895	$ -	$ -	$ -	$ -	**$ 1,895**
Risk Management Liabilities	25	5	-	-	-	**30**
Long-Term Debt (1)	1,408	758	2,102	2,150	6,633	**13,051**

(1) Principal and interest.

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As Encana operates primarily in North America, fluctuations in the exchange rate between the U.S. and Canadian dollars can have a significant effect on the Company's reported results. Encana's financial results are consolidated in Canadian dollars; however, the Company reports its results in U.S. dollars as most of its revenue is closely tied to the U.S. dollar and to facilitate a more direct comparison to other North American oil and gas companies. As the effects of foreign exchange fluctuations are embedded in the Company's results, the total effect of foreign exchange fluctuations is not separately identifiable.

To mitigate the exposure to the fluctuating U.S./Canadian dollar exchange rate, Encana maintains a mix of both U.S. dollar and Canadian dollar debt and may also enter into foreign exchange derivatives. As at December 31, 2013, Encana had $5.4 billion in U.S. dollar debt issued from Canada that was subject to foreign exchange exposure (2012 - $5.9 billion) and $1.7 billion in debt that was not subject to foreign exchange exposure (2012 - $1.8 billion). There were no foreign exchange derivatives outstanding as at December 31, 2013.

Encana's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt issued from Canada, unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated risk management assets and liabilities held in Canada and foreign exchange gains and losses on U.S. dollar denominated cash and short-term investments held in Canada. A $0.01 change in the U.S. to Canadian dollar exchange rate would have resulted in a $48 million change in foreign exchange (gain) loss as at December 31, 2013 (2012 - $51 million).

Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect the fair value or future cash flows from the Company's financial assets or liabilities. The Company may partially mitigate its exposure to interest rate changes by holding a mix of both fixed and floating rate debt and may also enter into interest rate derivatives to partially mitigate effects of fluctuations in market interest rates. There were no interest rate derivatives outstanding as at December 31, 2013.

As at December 31, 2013, the Company had no floating rate debt. Accordingly, the sensitivity in net earnings for each one percent change in interest rates on floating rate debt was nil (2012 - nil).

Notes to Condensed Consolidated Financial Statements *(unaudited)*

(All amounts in $ millions unless otherwise specified)

19. Commitments and Contingencies

Commitments

The following table outlines the Company's commitments as at December 31, 2013:

	Expected Future Payments						
(undiscounted)	2014	2015	2016	2017	2018	Thereafter	Total
Transportation and Processing	$ 967	$ 985	$ 896	$ 896	$ 848	$ 4,379	**$ 8,971**
Drilling and Field Services	292	106	71	41	38	35	**583**
Operating Leases	47	43	38	31	28	38	**225**
Total	$ 1,306	$ 1,134	$ 1,005	$ 968	$ 914	$ 4,452	**$ 9,779**

Contingencies

Encana is involved in various legal claims and actions arising in the course of the Company's operations. Although the outcome of these claims cannot be predicted with certainty, the Company does not expect these matters to have a material adverse effect on Encana’s financial position, cash flows or results of operations. If an unfavourable outcome were to occur, there exists the possibility of a material adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims.

Supplemental Financial Information *(unaudited)*

Financial Results

($ millions, except per share amounts)	2013					2012				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Cash Flow [1]	**2,581**	**677**	660	665	579	3,537	809	913	794	1,021
Per share - Diluted [3]	**3.50**	**0.91**	0.89	0.90	0.79	4.80	1.10	1.24	1.08	1.39
Operating Earnings [2]	**802**	**226**	150	247	179	997	296	263	198	240
Per share - Diluted [3]	**1.09**	**0.31**	0.20	0.34	0.24	1.35	0.40	0.36	0.27	0.33
Net Earnings (Loss)	**236**	**(251)**	188	730	(431)	(2,794)	(80)	(1,244)	(1,482)	12
Per share - Diluted [3]	**0.32**	**(0.34)**	0.25	0.99	(0.59)	(3.79)	(0.11)	(1.69)	(2.01)	0.02
Effective Tax Rate using										
Canadian Statutory Rate	**25.1%**					25.0%				
Foreign Exchange Rates (US$ per C$1)										
Average	**0.971**	**0.953**	0.963	0.977	0.992	1.000	1.009	1.005	0.990	0.999
Period end	**0.940**	**0.940**	0.972	0.951	0.985	1.005	1.005	1.017	0.981	1.001
Cash Flow Summary										
Cash From (Used in) Operating Activities	**2,289**	**462**	935	554	338	3,107	717	1,142	631	617
Deduct (Add back):										
Net change in other assets and liabilities	**(80)**	**(21)**	(15)	(22)	(22)	(78)	(23)	(9)	(26)	(20)
Net change in non-cash working capital	**(179)**	**(183)**	300	(81)	(215)	(323)	(56)	242	(134)	(375)
Cash tax on sale of assets	**(33)**	**(11)**	(10)	(8)	(4)	(29)	(13)	(4)	(3)	(9)
Cash Flow [1]	**2,581**	**677**	660	665	579	3,537	809	913	794	1,021
Operating Earnings Summary										
Net Earnings (Loss)	**236**	**(251)**	188	730	(431)	(2,794)	(80)	(1,244)	(1,482)	12
After-tax (addition) deduction:										
Unrealized hedging gain (loss)	**(232)**	**(209)**	(89)	332	(266)	(1,002)	(72)	(428)	(547)	45
Impairments	**(16)**	**-**	(16)	-	-	(3,188)	(300)	(1,193)	(1,695)	-
Restructuring charges	**(64)**	**(64)**	-	-	-	-	-	-	-	-
Non-operating foreign exchange gain (loss)	**(282)**	**(124)**	105	(162)	(101)	92	(66)	162	(90)	86
Income tax adjustments	**28**	**(80)**	38	313	(243)	307	62	(48)	652	(359)
Operating Earnings [2]	**802**	**226**	150	247	179	997	296	263	198	240

(1) Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and cash tax on sale of assets.

(2) Operating Earnings is a non-GAAP measure defined as Net Earnings excluding non-recurring or non-cash items that Management believes reduces the comparability of the Company's financial performance between periods. These after-tax items may include, but are not limited to, unrealized hedging gains/losses, impairments, restructuring charges, foreign exchange gains/losses, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective tax rate.

(3) Net earnings, operating earnings and cash flow per common share are calculated using the weighted average number of Encana common shares outstanding as follows:

	2013					2012				
(millions)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Weighted Average Common Shares Outstanding										
Basic	**737.7**	**740.4**	738.3	736.1	736.2	736.3	736.3	736.3	736.3	736.3
Diluted	**737.7**	**740.4**	738.3	736.1	736.2	736.3	736.3	736.3	736.3	736.3

Supplemental Financial & Operating Information *(unaudited)*

Financial Metrics	**2013**	2012
	Year	Year
Net Debt to Debt Adjusted Cash Flow	**1.5x**	1.1x
Debt to Debt Adjusted Cash Flow	**2.4x**	2.0x
Debt to Adjusted EBITDA	**2.5x**	2.0x
Debt to Adjusted Capitalization	**36%**	37%

The financial metrics disclosed above are non-GAAP measures monitored by Management as indicators of the Company's overall financial strength. These non-GAAP measures are defined and calculated in the Non-GAAP Measures section of Encana's Management's Discussion and Analysis.

Net Capital Investment	**2013**					2012				
($ millions)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment										
Canadian Division	**1,365**	**354**	301	301	409	1,567	373	356	323	515
USA Division	**1,283**	**343**	330	327	283	1,727	352	380	432	563
Market Optimization	**3**	**1**	-	2	-	7	-	-	1	6
Corporate & Other	**61**	**19**	10	9	23	175	55	43	41	36
Capital Investment	**2,712**	**717**	641	639	715	3,476	780	779	797	1,120
Net Acquisitions & (Divestitures) [(1)]	**(776)**	**(72)**	(51)	(312)	(341)	(3,664)	(1,327)	31	(8)	(2,360)
Net Capital Investment	**1,936**	**645**	590	327	374	(188)	(547)	810	789	(1,240)

(1) Q1 2013 Net Acquisitions & (Divestitures) includes proceeds received from the sale of the Company's 30 percent interest in the proposed Kitimat liquefied natural gas export terminal in British Columbia and associated undeveloped lands in the Horn River Basin. The transaction closed on February 8, 2013.

Production Volumes - After Royalties	**2013**					2012				
(average)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas (MMcf/d)										
Canadian Division	**1,432**	**1,528**	1,414	1,364	1,422	1,359	1,408	1,299	1,237	1,493
USA Division	**1,345**	**1,216**	1,309	1,402	1,455	1,622	1,540	1,606	1,565	1,779
	2,777	**2,744**	2,723	2,766	2,877	2,981	2,948	2,905	2,802	3,272
Oil (Mbbls/d)										
Canadian Division	**11.9**	**16.8**	12.3	10.3	8.0	7.3	7.6	7.1	7.4	7.2
USA Division	**13.9**	**16.2**	14.9	12.6	12.0	10.3	10.9	10.4	10.5	9.3
	25.8	**33.0**	27.2	22.9	20.0	17.6	18.5	17.5	17.9	16.5
NGLs (Mbbls/d)										
Canadian Division	**18.5**	**21.7**	20.5	15.7	16.0	12.1	16.0	10.9	9.5	12.0
USA Division	**9.6**	**11.3**	10.5	9.0	7.5	1.3	1.7	1.9	0.8	0.8
	28.1	**33.0**	31.0	24.7	23.5	13.4	17.7	12.8	10.3	12.8
Oil & NGLs (Mbbls/d)										
Canadian Division	**30.4**	**38.5**	32.8	26.0	24.0	19.4	23.6	18.0	16.9	19.2
USA Division	**23.5**	**27.5**	25.4	21.6	19.5	11.6	12.6	12.3	11.3	10.1
	53.9	**66.0**	58.2	47.6	43.5	31.0	36.2	30.3	28.2	29.3

Oil & NGLs Production Volumes - After Royalties	**2013**		2012	
(average Mbbls/d)	**Year**	% of Total	Year	% of Total
Oil	**25.8**	49	17.6	57
Plant Condensate	**8.7**	16	6.5	21
Butane	**4.5**	8	2.0	6
Propane	**7.2**	13	2.5	8
Ethane	**7.7**	14	2.4	8
	53.9	100	31.0	100

Supplemental Financial & Operating Information *(unaudited)*

Results of Operations

Product and Divisional Information, Including the Impact of Realized Financial Hedging

	2013					2012				
($ millions)	**Year**	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas - Canadian Division										
Revenues, Net of Royalties, excluding Hedging	**1,771**	**509**	381	459	422	1,263	411	282	223	347
Realized Financial Hedging Gain	**271**	**84**	102	19	66	962	187	261	286	228
Expenses										
Production and mineral taxes	**4**	**2**	1	-	1	1	1	-	1	(1)
Transportation and processing	**724**	**207**	183	165	169	549	158	116	143	132
Operating	**322**	**82**	72	80	88	327	71	86	78	92
Operating Cash Flow	**992**	**302**	227	233	230	1,348	368	341	287	352
Natural Gas - USA Division										
Revenues, Net of Royalties, excluding Hedging	**1,872**	**426**	440	547	459	1,798	523	446	343	486
Realized Financial Hedging Gain	**260**	**80**	84	27	69	1,195	238	300	355	302
Expenses										
Production and mineral taxes	**77**	**19**	16	27	15	68	28	22	5	13
Transportation and processing	**722**	**175**	184	179	184	652	162	169	148	173
Operating	**339**	**97**	78	78	86	347	78	90	81	98
Operating Cash Flow	**994**	**215**	246	290	243	1,926	493	465	464	504
Natural Gas - Total										
Revenues, Net of Royalties, excluding Hedging	**3,643**	**935**	821	1,006	881	3,061	934	728	566	833
Realized Financial Hedging Gain	**531**	**164**	186	46	135	2,157	425	561	641	530
Expenses										
Production and mineral taxes	**81**	**21**	17	27	16	69	29	22	6	12
Transportation and processing	**1,446**	**382**	367	344	353	1,201	320	285	291	305
Operating	**661**	**179**	150	158	174	674	149	176	159	190
Operating Cash Flow	**1,986**	**517**	473	523	473	3,274	861	806	751	856
Liquids - Canadian Division										
Revenues, Net of Royalties, excluding Hedging	**722**	**222**	204	156	140	504	132	114	118	140
Realized Financial Hedging Gain (Loss)	**5**	**6**	(7)	2	4	(4)	(4)	-	-	-
Expenses										
Production and mineral taxes	**11**	**2**	7	1	1	8	1	1	2	4
Transportation and processing	**32**	**18**	7	4	3	6	2	1	2	1
Operating	**39**	**7**	11	9	12	14	7	2	3	2
Operating Cash Flow	**645**	**201**	172	144	128	472	118	110	111	133
Liquids - USA Division										
Revenues, Net of Royalties, excluding Hedging	**602**	**177**	169	134	122	348	89	88	88	83
Realized Financial Hedging Gain (Loss)	**4**	**3**	(7)	3	5	-	-	-	-	-
Expenses										
Production and mineral taxes	**42**	**14**	11	9	8	28	6	7	7	8
Transportation and processing	**-**	**-**	-	-	-	-	-	-	-	-
Operating	**59**	**10**	12	14	23	25	8	9	6	2
Operating Cash Flow	**505**	**156**	139	114	96	295	75	72	75	73
Liquids - Total										
Revenues, Net of Royalties, excluding Hedging	**1,324**	**399**	373	290	262	852	221	202	206	223
Realized Financial Hedging Gain (Loss)	**9**	**9**	(14)	5	9	(4)	(4)	-	-	-
Expenses										
Production and mineral taxes	**53**	**16**	18	10	9	36	7	8	9	12
Transportation and processing	**32**	**18**	7	4	3	6	2	1	2	1
Operating	**98**	**17**	23	23	35	39	15	11	9	4
Operating Cash Flow	**1,150**	**357**	311	258	224	767	193	182	186	206

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties

Per-unit Results, Excluding the Impact of Realized Financial Hedging

	2013					2012				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas - Canadian Division ($/Mcf)										
Price	**3.35**	**3.60**	2.90	3.69	3.21	2.58	3.18	2.45	2.05	2.56
Production and mineral taxes	**0.01**	**0.02**	0.01	-	0.01	-	0.01	-	0.01	(0.01)
Transportation and processing	**1.37**	**1.46**	1.38	1.33	1.29	1.12	1.23	1.01	1.31	0.97
Operating	**0.61**	**0.59**	0.55	0.65	0.66	0.67	0.55	0.75	0.71	0.68
Netback	**1.36**	**1.53**	0.96	1.71	1.25	0.79	1.39	0.69	0.02	0.92
Natural Gas - USA Division ($/Mcf)										
Price	**3.81**	**3.81**	3.66	4.29	3.50	3.03	3.68	3.02	2.41	3.00
Production and mineral taxes	**0.16**	**0.18**	0.13	0.21	0.11	0.11	0.19	0.15	0.03	0.08
Transportation and processing	**1.47**	**1.56**	1.53	1.40	1.40	1.10	1.15	1.14	1.04	1.07
Operating	**0.69**	**0.86**	0.65	0.61	0.66	0.59	0.55	0.62	0.56	0.61
Netback	**1.49**	**1.21**	1.35	2.07	1.33	1.23	1.79	1.11	0.78	1.24
Natural Gas - Total ($/Mcf)										
Price	**3.57**	**3.69**	3.26	3.99	3.35	2.83	3.45	2.77	2.25	2.80
Production and mineral taxes	**0.08**	**0.09**	0.07	0.11	0.06	0.06	0.10	0.08	0.02	0.04
Transportation and processing	**1.42**	**1.51**	1.46	1.36	1.35	1.11	1.18	1.08	1.16	1.02
Operating	**0.65**	**0.70**	0.60	0.63	0.66	0.62	0.55	0.68	0.63	0.64
Netback	**1.42**	**1.39**	1.13	1.89	1.28	1.04	1.62	0.93	0.44	1.10
Liquids - Canadian Division ($/bbl)										
Price	**65.06**	**62.80**	67.33	65.88	64.72	70.84	61.04	68.80	76.47	79.96
Production and mineral taxes	**0.96**	**0.61**	1.91	0.62	0.58	1.13	0.43	0.62	1.28	2.36
Transportation and processing	**2.89**	**5.15**	2.41	1.53	1.33	0.75	0.78	0.10	1.18	0.95
Operating	**3.56**	**2.03**	3.74	3.77	5.61	2.09	3.60	1.48	1.68	1.15
Netback	**57.65**	**55.01**	59.27	59.96	57.20	66.87	56.23	66.60	72.33	75.50
Liquids - USA Division ($/bbl)										
Price	**70.18**	**69.46**	72.53	68.56	69.91	82.33	77.18	77.12	86.11	91.05
Production and mineral taxes	**4.79**	**5.06**	4.90	4.57	4.50	6.63	5.00	6.46	7.17	8.33
Transportation and processing	**-**	**-**	-	-	-	0.06	-	-	0.09	0.20
Operating	**7.02**	**4.11**	5.13	7.54	13.16	5.88	7.05	7.69	5.52	2.59
Netback	**58.37**	**60.29**	62.50	56.45	52.25	69.76	65.13	62.97	73.33	79.93
Liquids - Total ($/bbl)										
Price	**67.30**	**65.58**	69.60	67.10	67.04	75.12	66.65	72.17	80.32	83.77
Production and mineral taxes	**2.63**	**2.46**	3.22	2.41	2.33	3.18	2.02	2.98	3.63	4.41
Transportation and processing	**1.63**	**3.01**	1.36	0.84	0.73	0.50	0.51	0.06	0.75	0.69
Operating	**5.07**	**2.90**	4.35	5.48	8.98	3.50	4.80	3.98	3.21	1.65
Netback	**57.97**	**57.21**	60.67	58.37	55.00	67.94	59.32	65.15	72.73	77.02

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Operating Statistics - After Royalties (continued)

Impact of Realized Financial Hedging

	2013					2012				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas ($/Mcf)										
Canadian Division	**0.51**	**0.60**	0.78	0.15	0.50	1.97	1.45	2.27	2.61	1.69
USA Division	**0.53**	**0.72**	0.69	0.21	0.53	2.01	1.68	2.03	2.49	1.86
Total	**0.52**	**0.65**	0.74	0.18	0.51	1.99	1.57	2.14	2.54	1.78
Liquids ($/bbl)										
Canadian Division	**0.46**	**1.62**	(2.59)	1.00	2.20	-	-	-	-	-
USA Division	**0.44**	**1.15**	(2.73)	1.32	2.67	-	-	-	-	-
Total	**0.45**	**1.43**	(2.65)	1.15	2.41	-	-	-	-	-

Per-unit Results, Including the Impact of Realized Financial Hedging

	2013					2012				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas Price ($/Mcf)										
Canadian Division	**3.86**	**4.20**	3.68	3.84	3.71	4.55	4.63	4.72	4.66	4.25
USA Division	**4.34**	**4.53**	4.35	4.50	4.03	5.04	5.36	5.05	4.90	4.86
Total	**4.09**	**4.34**	4.00	4.17	3.86	4.82	5.02	4.91	4.79	4.58
Natural Gas Netback ($/Mcf)										
Canadian Division	**1.87**	**2.13**	1.74	1.86	1.75	2.76	2.84	2.96	2.63	2.61
USA Division	**2.02**	**1.93**	2.04	2.28	1.86	3.24	3.47	3.14	3.27	3.10
Total	**1.94**	**2.04**	1.87	2.07	1.79	3.03	3.19	3.07	2.98	2.88
Liquids Price ($/bbl)										
Canadian Division	**65.52**	**64.42**	64.74	66.88	66.92	70.84	61.04	68.80	76.47	79.96
USA Division	**70.62**	**70.61**	69.80	69.88	72.58	82.33	77.18	77.12	86.11	91.05
Total	**67.75**	**67.01**	66.95	68.25	69.45	75.12	66.65	72.17	80.32	83.77
Liquids Netback ($/bbl)										
Canadian Division	**58.11**	**56.63**	56.68	60.96	59.40	66.87	56.23	66.60	72.33	75.50
USA Division	**58.81**	**61.44**	59.77	57.77	54.92	69.76	65.13	62.97	73.33	79.93
Total	**58.42**	**58.64**	58.02	59.52	57.41	67.94	59.32	65.15	72.73	77.02

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Resource Play

	2013					2012				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Natural Gas Production (MMcf/d) - After Royalties										
Canadian Division										
Cutbank Ridge	**506**	**517**	554	472	482	433	431	447	377	476
Bighorn	**255**	**283**	253	242	243	242	244	235	263	227
Peace River Arch	**133**	**160**	138	119	115	108	116	99	99	119
Clearwater	**335**	**329**	332	331	347	374	366	336	353	440
Greater Sierra	**156**	**97**	105	195	232	200	245	182	142	231
Other and emerging	**47**	**142**	32	5	3	2	6	-	3	-
Total Canadian Division	**1,432**	**1,528**	1,414	1,364	1,422	1,359	1,408	1,299	1,237	1,493
USA Division										
Piceance	**455**	**452**	444	465	459	475	467	476	470	488
Jonah	**323**	**296**	320	332	346	411	365	407	426	448
Haynesville	**348**	**261**	336	375	420	475	464	475	418	545
Texas	**136**	**123**	132	145	145	167	151	157	158	201
Other and emerging	**83**	**84**	77	85	85	94	93	91	93	97
Total USA Division	**1,345**	**1,216**	1,309	1,402	1,455	1,622	1,540	1,606	1,565	1,779
Oil & NGLs Production (Mbbls/d) - After Royalties										
Canadian Division										
Cutbank Ridge	**1.8**	**1.8**	2.0	1.9	1.6	1.5	1.5	1.6	1.5	1.2
Bighorn	**8.9**	**10.9**	9.9	7.4	7.4	5.8	9.4	5.0	3.4	5.5
Peace River Arch	**8.7**	**12.4**	10.4	6.4	5.6	2.9	3.6	2.7	2.5	2.7
Clearwater	**9.9**	**12.2**	9.8	9.2	8.5	8.6	8.1	8.0	9.0	9.2
Greater Sierra	**0.3**	**-**	-	0.5	0.6	0.5	0.6	0.4	0.3	0.6
Other and emerging	**0.8**	**1.2**	0.7	0.6	0.3	0.1	0.4	0.3	0.2	-
Total Canadian Division	**30.4**	**38.5**	32.8	26.0	24.0	19.4	23.6	18.0	16.9	19.2
USA Division										
Piceance	**5.1**	**5.3**	5.5	5.2	4.3	2.2	2.5	2.7	2.0	1.6
Jonah	**4.7**	**4.6**	4.8	4.9	4.6	4.1	4.0	4.3	4.0	4.1
Haynesville	**-**	**-**	-	-	-	-	-	-	0.1	-
Texas	**-**	**-**	-	-	-	0.1	-	0.1	-	0.2
Other and emerging	**13.7**	**17.6**	15.1	11.5	10.6	5.2	6.1	5.2	5.2	4.2
Total USA Division	**23.5**	**27.5**	25.4	21.6	19.5	11.6	12.6	12.3	11.3	10.1
Capital Investment ($ millions)										
Canadian Division										
Cutbank Ridge	**143**	**45**	28	19	51	228	60	53	35	80
Bighorn	**268**	**39**	68	56	105	333	66	82	63	122
Peace River Arch	**435**	**140**	109	85	101	220	55	56	52	57
Clearwater	**128**	**23**	26	15	64	131	37	17	14	63
Greater Sierra	**17**	**1**	1	6	9	118	14	13	47	44
Other and emerging	**374**	**106**	69	120	79	537	141	135	112	149
Total Canadian Division	**1,365**	**354**	301	301	409	1,567	373	356	323	515
USA Division										
Piceance	**241**	**61**	81	51	48	328	42	68	112	106
Jonah	**48**	**12**	15	13	8	102	15	13	25	49
Haynesville	**210**	**79**	44	55	32	337	16	46	90	185
Texas	**23**	**10**	5	3	5	62	3	14	16	29
Other and emerging	**761**	**181**	185	205	190	898	276	239	189	194
Total USA Division	**1,283**	**343**	330	327	283	1,727	352	380	432	563

Supplemental Oil and Gas Operating Statistics *(unaudited)*

Results by Resource Play (continued)

	2013					2012				
	Year	**Q4**	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Drilling Activity (net wells drilled)										
Canadian Division										
Cutbank Ridge	**30**	**10**	6	7	7	41	13	14	7	7
Bighorn	**21**	**1**	3	9	8	31	5	6	9	11
Peace River Arch	**39**	**9**	9	10	11	26	6	7	7	6
Clearwater	**283**	**115**	81	-	87	260	84	93	-	83
Greater Sierra	**5**	**1**	1	1	2	6	-	-	-	6
Other and emerging	**12**	**4**	4	2	2	8	3	2	2	1
Total Canadian Division	**390**	**140**	104	29	117	372	111	122	25	114
USA Division										
Piceance	**85**	**20**	20	23	22	116	21	21	35	39
Jonah	**49**	**9**	13	13	14	41	11	9	7	14
Haynesville	**19**	**7**	5	5	2	17	1	-	4	12
Texas	**1**	**1**	-	-	-	4	-	1	-	3
Other and emerging	**83**	**19**	24	21	19	107	33	35	14	25
Total USA Division	**237**	**56**	62	62	57	285	66	66	60	93