Encana Corporation

Management's Discussion and Analysis

For the year ended December 31, 2015

(Prepared in U.S. Dollars)

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 period ended December 31, 2015 ("Consolidated Financial Statements"), as well as the audited Consolidated Financial Statements and MD&A for the year ended December 31, 2014.

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. 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. 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" or "NGL") and condensate. The term "liquids rich" is used to represent natural gas streams with associated liquids volumes. This document is dated February 29, 2016.

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.

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; Free Cash Flow; Operating Earnings (Loss); Upstream Operating Cash Flow, excluding Hedging; Operating Netback; Debt to Debt Adjusted Cash Flow; 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 Free Cash Flow, and of Net Earnings (Loss) Attributable to Common Shareholders to Operating Earnings (Loss).

The following volumetric measures may be abbreviated throughout this MD&A: thousand cubic feet ("Mcf"); million cubic feet ("MMcf") per day ("MMcf/d"); billion cubic feet ("Bcf") per day ("Bcf/d"); trillion cubic feet ("Tcf"); barrel ("bbl"); thousand barrels ("Mbbls") per day ("Mbbls/d"); million barrels ("MMbbls"); barrels of oil equivalent ("BOE") per day ("BOE/d"); thousand barrels of oil equivalent ("MBOE") per day ("MBOE/d"); million barrels of oil equivalent ("MMBOE"); 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 and Oil and Gas Information.

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 portfolio, focusing capital investments in a limited number of core, high return and scalable projects, maintaining portfolio flexibility to respond to changing market conditions, maximizing profitability through operating efficiencies, reducing costs and preserving balance sheet strength.

Encana continually strives to improve operating efficiencies, foster technological innovation and lower its cost structures, while reducing its environmental footprint through play optimization. The Company's resource play hub model utilizes highly integrated production facilities to develop resources by drilling multiple wells from central pad sites. Capital and operating efficiencies are achieved through repeatable operations, optimizing equipment and processes and 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 Operating Netbacks during periods of lower prices. Further information on the Company's commodity price positions as at December 31, 2015 can be found in the Results Overview section of this MD&A and in Note 24 to the Consolidated Financial Statements.

Additional information on expected results can be found in Encana's 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 Operations** includes the exploration for, development of, and production of natural gas, oil and NGLs and other related activities within Canada.

- **USA Operations** 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 reported in the Canadian and USA Operations. Market optimization activities include third party purchases and sales of product to provide operational flexibility and cost mitigation 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 instruments relate.

Comparative figures for 2014 and 2013 have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Further information regarding the reclassification can be found in the Results of Operations section of this MD&A.

Results Overview

Highlights

In the year ended December 31, 2015, Encana reported:

- Cash Flow of $1,430 million and an Operating Loss of $61 million.
- Net Loss of $5,165 million, including after-tax non-cash ceiling test impairments of $4,130 million and an after-tax non-operating foreign exchange loss of $702 million.
- Average realized natural gas prices, including financial hedges, of $3.89 per Mcf. Average realized oil prices, including financial hedges, of $49.68 per bbl. Average realized NGL prices of $21.66 per bbl.
- Average natural gas production volumes of 1,635 MMcf/d and average oil and NGL production volumes of 133.4 Mbbls/d.
- Dividends paid of $0.28 per share.
- Cash and cash equivalents of $271 million at year end.

Significant developments for the Company during the year ended December 31, 2015 included the following:

- Closed the sale of the Company's Haynesville natural gas assets located in northern Louisiana to GEP Haynesville, LLC ("GeoSouthern") on November 12, 2015 for proceeds of approximately $769 million, after closing adjustments. Based on the January 1, 2015 effective date of the transaction, Encana also reduced its gathering and midstream commitments by approximately $480 million (undiscounted) through the transfer of current and future obligations and will transport and market GeoSouthern's Haynesville production on a fee for service basis for the next five years.
- Announced an agreement on October 8, 2015 to sell to Crestone Peak Resources Holdings LLC, an entity jointly owned by the Canada Pension Plan Investment Board and The Broe Group, the Company's DJ Basin assets in Colorado, comprising approximately 51,000 net acres, for an announced purchase price of approximately $900 million, before post-closing and other adjustments. The transaction, previously expected to close in the fourth quarter of 2015, is expected to close by the end of the second quarter of 2016, with an effective date of April 1, 2015, and is subject to satisfaction of certain closing conditions.
- Completed a bought deal offering of 98,458,975 common shares of Encana, including common shares issued under an over-allotment option, at a price of C$14.60 per common share (the "Share Offering"). The Share Offering was completed during March 2015 for aggregate gross proceeds of approximately C$1.44 billion.
- Redeemed the Company's $700 million 5.90 percent notes due December 1, 2017 and its C$750 million 5.80 percent medium-term notes due January 18, 2018, in April 2015, using net proceeds from the Share Offering and cash on hand.
- Closed the sale of the Company's working interest in certain properties in central and southern Alberta to Ember Resources Inc. on January 15, 2015 for proceeds of approximately C$557 million, after closing adjustments.
- Closed the sale of certain natural gas gathering and compression assets in northeastern British Columbia to Veresen Midstream Limited Partnership ("VMLP") on March 31, 2015 for cash consideration net to Encana of approximately C$450 million, after closing adjustments.

Financial Results

($ millions, except as indicated)	2015 Annual	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Annual	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Annual
Cash Flow [1]	**$ 1,430**	**$ 383**	**$ 371**	**$ 181**	**$ 495**	$ 2,934	$ 377	$ 807	$ 656	$ 1,094	$ 2,581
$ per share - diluted	**1.74**	**0.45**	**0.44**	**0.22**	**0.65**	3.96	0.51	1.09	0.89	1.48	3.50
Operating Earnings (Loss) [1], [2]	**(61)**	**111**	**(24)**	**(167)**	**19**	1,002	35	281	171	515	802
$ per share - diluted	**(0.07)**	**0.13**	**(0.03)**	**(0.20)**	**0.03**	1.35	0.05	0.38	0.23	0.70	1.09
Net Earnings (Loss) Attributable to Common Shareholders	**(5,165)**	**(612)**	**(1,236)**	**(1,610)**	**(1,707)**	3,392	198	2,807	271	116	236
$ per share - basic & diluted	**(6.28)**	**(0.72)**	**(1.47)**	**(1.91)**	**(2.25)**	4.58	0.27	3.79	0.37	0.16	0.32
Revenues, Net of Royalties	**4,422**	**1,031**	**1,312**	**830**	**1,249**	8,019	2,254	2,285	1,588	1,892	5,858
Realized Hedging Gain (Loss), before tax	**901**	**287**	**213**	**161**	**240**	(91)	124	28	(102)	(141)	544
Unrealized Hedging Gain (Loss), before tax	**(331)**	**(90)**	**173**	**(278)**	**(136)**	444	489	231	9	(285)	(345)
Upstream Operating Cash Flow	**2,264**	**552**	**531**	**479**	**702**	3,918	821	982	800	1,315	3,192
Upstream Operating Cash Flow, excluding Hedging [1]	**1,344**	**261**	**314**	**315**	**454**	3,999	694	952	898	1,455	2,652
Capital Investment	**2,232**	**280**	**473**	**743**	**736**	2,526	857	598	560	511	2,712
Net Acquisitions & (Divestitures) [3]	**(1,838)**	**(761)**	**(99)**	**(140)**	**(838)**	(1,329)	50	(2,007)	652	(24)	(521)
Free Cash Flow [1]	**(802)**	**103**	**(102)**	**(562)**	**(241)**	408	(480)	209	96	583	(131)
Ceiling Test Impairments, after tax	**(4,130)**	**(514)**	**(1,066)**	**(1,328)**	**(1,222)**	-	-	-	-	-	-
Gain (Loss) on Divestitures, after tax	**9**	**-**	**(2)**	**1**	**10**	2,523	(11)	2,399	135	-	-
Total Assets [4]	**15,644**					24,531					17,645
Total Debt	**5,363**					7,340					7,124
Cash & Cash Equivalents	**271**					338					2,566
Production Volumes											
Natural Gas (MMcf/d)	**1,635**	**1,571**	**1,547**	**1,568**	**1,857**	2,350	1,861	2,199	2,541	2,809	2,777
Oil & NGLs (Mbbls/d)											
Oil	**87.0**	**90.6**	**91.9**	**86.2**	**79.2**	49.4	68.8	62.1	34.2	32.1	25.8
NGLs	**46.4**	**54.4**	**48.5**	**41.1**	**41.5**	37.4	37.6	41.9	34.0	35.8	28.1
Total Oil & NGLs	**133.4**	**145.0**	**140.4**	**127.3**	**120.7**	86.8	106.4	104.0	68.2	67.9	53.9
Total Production (MBOE/d)	**405.9**	**406.8**	**398.3**	**388.7**	**430.1**	478.5	416.7	470.6	491.8	536.1	516.7
Production Mix (%)											
Natural Gas	**67**	**64**	**65**	**67**	**72**	82	74	78	86	87	90
Oil & NGLs	**33**	**36**	**35**	**33**	**28**	18	26	22	14	13	10

(1) A non-GAAP measure, which is defined in the Non-GAAP Measures section of this MD&A.
(2) In continued support of Encana's strategy, organizational structure changes were formalized in Q2 2015 and resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.
(3) Excludes the impact of the PrairieSky Royalty Ltd. divestiture and the Athlon Energy Inc. acquisition during 2014, as summarized in the Net Capital Investment section of this MD&A.
(4) 2014 and 2013 have been restated due to the early adoption of Accounting Standard Update 2015-17, *Balance Sheet Classification of Deferred Taxes*, as discussed in the Accounting Policies and Estimates section of this MD&A.

Factors Impacting Quarterly Net Earnings

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, ceiling test impairments and gains or losses on divestitures, which are provided in the Financial Results table and 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, and by acquisition and divestiture transactions as discussed in the Net Capital Investment section of this MD&A.

Ceiling Test Impairments

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. Ceiling test impairments are recognized when the capitalized costs, net of accumulated depletion and the related deferred income taxes, exceed the sum of the estimated after-tax future net cash flows from proved reserves as calculated under Securities and Exchange Commission ("SEC") requirements using the 12-month average trailing prices and discounted at 10 percent.

In 2015, the Company recognized after-tax non-cash ceiling test impairments of $4,130 million in the USA Operations. The non-cash ceiling test impairments primarily resulted from the decline in the 12-month average trailing prices. Further declines in the 12-month average trailing prices could reduce proved reserves volumes and values and result in the recognition of future ceiling test impairments.

Future ceiling test impairments are difficult to reasonably predict and depend on commodity prices, as well as changes to reserves estimates, future development costs, capitalized costs and unproved property costs. Proceeds received from natural gas and oil property divestitures are generally deducted from the Company's capitalized costs and can reduce the likelihood of ceiling test impairments.

The Company has calculated the estimated effects that certain price changes would have had on its ceiling test impairment for the year ended December 31, 2015. Using the average of the price on the first day of each month from the most recent nine months of 2015 and commodity futures prices for the first three months of 2016, the 12-month average trailing prices for the year ended December 31, 2015 would have been $47.28 per bbl for WTI, C$58.61 per bbl for Edmonton Light Sweet, $2.47 per MMBtu for Henry Hub, and C$2.59 per MMBtu for AECO, while holding all other inputs and assumptions constant. Based on these estimated prices, an additional after-tax ceiling test impairment of $174 million for the USA Operations and $2 million for the Canadian Operations would have been recognized for the year ended December 31, 2015. The additional estimated after-tax ceiling test impairment is partly a result of an 11 percent decrease in proved undeveloped reserves as certain locations would not be economic at these revised prices. This estimate strictly isolates the potential impact of commodity prices on the Company's proved reserves volumes and values. Due to uncertainties in estimating proved reserves, the additional after-tax ceiling test impairment described and resulting implications may not be indicative of Encana's future development plans, operating or financial results.

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 natural gas and oil properties or the future net cash flows expected to be generated from such properties. Additional information on the ceiling test calculation can be found in the Critical Accounting Estimates section of this MD&A.

Q4 2015 versus Q4 2014

Cash Flow of $383 million increased $6 million during the three months ended December 31, 2015 and was impacted by the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $2.13 per Mcf compared to $3.94 per Mcf in 2014 reflecting lower benchmark prices. Lower realized natural gas prices decreased revenues $263 million. Average realized liquids prices, excluding financial hedges, were $31.43 per bbl compared to $57.35 per bbl in 2014 reflecting lower benchmark prices. Lower realized liquids prices decreased revenues $330 million.
- Average natural gas production volumes of 1,571 MMcf/d decreased 290 MMcf/d from 1,861 MMcf/d in 2014 primarily due to divestitures, natural declines in Haynesville and Piceance and lower production from Deep Panuke, partially offset by successful drilling programs in Montney and Duvernay. Lower natural gas volumes decreased revenues $107 million. Average oil and NGL production volumes of 145.0 Mbbls/d increased 38.6 Mbbls/d from 106.4 Mbbls/d in 2014 primarily due to acquisitions and successful drilling programs in liquids rich plays. Higher oil and NGL volumes increased revenues $191 million.
- Realized financial hedging gains before tax were $287 million compared to $124 million in 2014.
- Transportation and processing expense decreased $56 million primarily due to the lower U.S./Canadian dollar exchange rate, divestitures and lower production from Deep Panuke, partially offset by higher volumes in Montney.
- Interest expense decreased $146 million primarily due to a one-time outlay of $125 million associated with the early redemption of senior notes assumed in conjunction with the acquisition of Athlon Energy Inc. ("Athlon") in the fourth quarter of 2014.
- Other expense decreased $38 million primarily due to transaction costs of $31 million associated with the acquisition of Athlon in the fourth quarter of 2014.
- Current tax expense was $4 million compared to $2 million in 2014. Cash Flow excludes cash tax on the sale of assets as discussed in the Non-GAAP measures section of this MD&A.

Operating Earnings in the fourth quarter of 2015 were $111 million compared to $35 million in 2014 primarily due to the items discussed in the Cash Flow section. Operating Earnings in the fourth quarter of 2015 were also impacted by lower depreciation, depletion and amortization ("DD&A"), lower long-term compensation costs due to the decrease in the Encana share price, higher foreign exchange losses on the revaluation of other monetary assets and liabilities and settlements, and changes in deferred tax.

Net Loss Attributable to Common Shareholders in the fourth quarter of 2015 was $612 million compared to Net Earnings Attributable to Common Shareholders of $198 million in 2014 primarily due to an after-tax non-cash ceiling test impairment and the items discussed in the Cash Flow and Operating Earnings sections. Net Loss in the fourth quarter of 2015 was also impacted by after-tax unrealized hedging losses.

2015 versus 2014

Cash Flow of $1,430 million decreased $1,504 million in the year ended December 31, 2015 and was impacted by the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $2.69 per Mcf compared to $4.78 per Mcf in 2014 reflecting lower benchmark prices. Lower realized natural gas prices decreased revenues $1,198 million. Average realized liquids prices, excluding financial hedges, were $35.80 per bbl compared to $67.24 per bbl in 2014 reflecting lower benchmark prices. Lower realized liquids prices decreased revenues $1,151 million.
- Average natural gas production volumes of 1,635 MMcf/d decreased 715 MMcf/d from 2,350 MMcf/d in 2014 primarily due to divestitures, natural declines in Haynesville and Piceance and lower production from Deep Panuke, partially offset by successful drilling programs in Montney and Duvernay. Lower natural gas volumes decreased revenues $1,305 million. Average oil and NGL production volumes of 133.4 Mbbls/d increased 46.6 Mbbls/d from 86.8 Mbbls/d in 2014 primarily due to acquisitions and successful drilling programs in liquids rich plays, partially offset by divestitures. Higher oil and NGL volumes increased revenues $766 million.
- Realized financial hedging gains before tax were $901 million compared to losses of $91 million in 2014.
- Transportation and processing expense decreased $244 million primarily due to divestitures, the lower U.S./Canadian dollar exchange rate and lower production from Deep Panuke, partially offset by higher volumes in Montney.
- Current tax was a recovery of $34 million compared to an expense of $243 million in 2014 as discussed in the Other Operating Results section of this MD&A. Cash Flow excludes cash tax on the sale of assets as discussed in the Non-GAAP measures section of this MD&A.

Operating Loss in 2015 was $61 million compared to Operating Earnings of $1,002 million in 2014 primarily due to the items discussed in the Cash Flow section. Operating Loss in 2015 was also impacted by higher foreign exchange losses on settlements and the revaluation of other monetary assets and liabilities, lower DD&A and changes in deferred tax.

Net Loss Attributable to Common Shareholders in 2015 was $5,165 million compared to Net Earnings Attributable to Common Shareholders of $3,392 million in 2014 primarily due to after-tax non-cash ceiling test impairments, a lower after-tax gain on divestitures and the items discussed in the Cash Flow and Operating Earnings sections. Net Loss in 2015 was also impacted by after-tax unrealized hedging losses, a higher after-tax non-operating foreign exchange loss and changes in deferred tax.

2014 versus 2013

Cash Flow of $2,934 million increased $353 million in the year ended December 31, 2014 and was impacted by the following significant items:

- Average realized natural gas prices, excluding financial hedges, were $4.78 per Mcf compared to $3.57 per Mcf in 2013 reflecting higher benchmark prices, including the impact of higher realized prices from Deep Panuke production. Higher realized natural gas prices increased revenues $1,067 million. Average realized liquids prices, excluding financial hedges, were $67.24 per bbl compared to $67.30 per bbl in 2013 reflecting lower WTI prices. Lower realized liquids prices decreased revenues $23 million.
- Average natural gas production volumes of 2,350 MMcf/d decreased 427 MMcf/d from 2,777 MMcf/d in 2013 primarily due to divestitures resulting from the Company's strategic transition to a more balanced commodity portfolio and natural declines, partially offset by production from Deep Panuke. Lower natural gas volumes decreased revenues $602 million. Average oil and NGL production volumes of 86.8 Mbbls/d increased 32.9 Mbbls/d from 53.9 Mbbls/d in 2013 primarily due to acquisitions and successful drilling programs in liquids rich plays, partially offset by divestitures and the sale of the Company's investment in PrairieSky Royalty Ltd. ("PrairieSky"). Higher oil and NGL volumes increased revenues $829 million.
- Realized financial hedging losses before tax were $91 million compared to gains of $544 million in 2013.
- Operating expense decreased $162 million primarily due to lower salaries and benefits related to workforce reductions resulting from the 2013 restructuring, divestitures and the lower U.S./Canadian dollar exchange rate, partially offset by acquisitions. The decrease also reflects lower non-cash long-term compensation costs resulting from the decrease in the Encana share price.
- Administrative expense decreased $112 million primarily due to lower restructuring charges of $52 million and the lower U.S./Canadian dollar exchange rate. The decrease also reflects lower non-cash long-term compensation costs resulting from the decrease in the Encana share price.
- Interest expense increased $91 million primarily due to a one-time outlay associated with the early redemption of senior notes assumed in conjunction with the acquisition of Athlon.
- Other expense increased $70 million primarily due to transaction costs of $40 million associated with the acquisitions of Athlon and Eagle Ford. The increase also reflects non-cash reclamation charges relating to non-producing assets.
- Current tax expense was $243 million compared to a recovery of $191 million in 2013 as discussed in the Other Operating Results section of this MD&A. Cash Flow excludes cash tax on the sale of assets as discussed in the Non-GAAP Measures section of this MD&A.

Operating Earnings of $1,002 million increased $200 million primarily due to the items discussed in the Cash Flow section. Operating Earnings in 2014 were also impacted by a higher foreign exchange gain on the revaluation of other monetary assets and higher DD&A. Operating Earnings excludes restructuring charges as described in the Non-GAAP Measures section of this MD&A.

Net Earnings Attributable to Common Shareholders of $3,392 million increased $3,156 million primarily due to gains on divestitures as well as the items discussed in the Cash Flow and Operating Earnings sections. Net Earnings Attributable to Common Shareholders in 2014 were also impacted by after-tax unrealized hedging gains, a higher after-tax non-operating foreign exchange loss and changes in deferred tax.

Prices and Foreign Exchange Rates

(average for the period)	2015 Annual	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Annual	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Annual
Encana Realized Pricing											
Including Hedging											
Natural Gas ($/Mcf)	**$ 3.89**	**$ 3.43**	**$ 3.71**	**$ 3.52**	**$ 4.78**	$ 4.59	$ 4.16	$ 4.03	$ 4.08	$ 5.82	$ 4.09
Oil & NGLs ($/bbl)											
Oil	**49.68**	**49.77**	**49.38**	**53.08**	**46.17**	86.03	80.38	90.22	89.55	86.34	88.19
NGLs	**21.66**	**21.36**	**19.57**	**24.28**	**21.92**	48.09	40.87	48.76	49.39	53.79	48.95
Total Oil & NGLs	**39.93**	**39.11**	**39.09**	**43.78**	**37.83**	69.70	66.40	73.50	69.53	69.19	67.75
Total ($/BOE)	**28.81**	**27.19**	**28.17**	**28.53**	**31.24**	35.21	35.55	35.06	30.75	39.22	29.05
Excluding Hedging											
Natural Gas ($/Mcf)	**2.69**	**2.13**	**2.60**	**2.37**	**3.53**	4.78	3.94	3.88	4.46	6.37	3.57
Oil & NGLs ($/bbl)											
Oil	**43.35**	**37.48**	**42.40**	**53.15**	**40.53**	81.71	66.38	90.18	92.93	86.43	87.25
NGLs	**21.66**	**21.36**	**19.57**	**24.28**	**21.92**	48.09	40.87	48.76	49.39	53.79	48.95
Total Oil & NGLs	**35.80**	**31.43**	**34.52**	**43.83**	**34.13**	67.24	57.35	73.48	71.23	69.23	67.30
Total ($/BOE)	**22.61**	**19.44**	**22.26**	**23.90**	**24.82**	35.67	32.25	34.36	32.93	42.12	26.20
Natural Gas Price Benchmarks											
NYMEX ($/MMBtu)	**2.66**	**2.27**	**2.77**	**2.64**	**2.98**	4.41	4.00	4.06	4.67	4.94	3.65
AECO (C$/Mcf)	**2.77**	**2.65**	**2.80**	**2.67**	**2.95**	4.42	4.01	4.22	4.68	4.76	3.16
Algonquin City Gate ($/MMBtu)	**4.74**	**3.05**	**2.37**	**2.24**	**11.41**	8.06	4.99	2.97	4.23	20.28	6.97
Basis Differential ($/MMBtu)											
AECO/NYMEX	**0.49**	**0.27**	**0.61**	**0.50**	**0.57**	0.39	0.44	0.16	0.40	0.60	0.57
Oil Price Benchmarks											
West Texas Intermediate (WTI) ($/bbl)	**48.80**	**42.18**	**46.43**	**57.94**	**48.64**	93.00	73.15	97.17	102.99	98.68	97.97
Edmonton Light Sweet (C$/bbl)	**57.21**	**52.95**	**56.23**	**67.71**	**51.94**	94.57	75.69	97.16	105.61	99.83	93.11
Foreign Exchange											
Average U.S./Canadian Dollar Exchange Rate	**0.782**	**0.749**	**0.764**	**0.813**	**0.806**	0.905	0.881	0.918	0.917	0.906	0.971

Encana's financial results are influenced by fluctuations in commodity prices, price differentials and the U.S./Canadian dollar exchange rate. In 2015, Encana's average realized natural gas price, excluding hedging, reflected lower benchmark prices compared to 2014. Hedging activities contributed $1.20 per Mcf to Encana's average realized natural gas price in 2015. The average realized natural gas price for production from Deep Panuke was $8.19 per Mcf in 2015 and increased Encana's average realized natural gas price $0.22 per Mcf. In 2015, Encana's average realized oil and NGL prices, excluding hedging, reflected lower benchmark prices compared to 2014. Hedging activities contributed $6.33 per bbl to Encana's average realized oil price in 2015.

In 2014, Encana's average realized natural gas price, excluding hedging, reflected higher benchmark prices compared to 2013. Hedging activities reduced Encana's average realized natural gas price $0.19 per Mcf in 2014. Realized natural gas prices for production from Deep Panuke were $8.34 per Mcf in 2014, which increased Encana's average realized natural gas price $0.31 per Mcf in 2014. In 2014, Encana's average realized oil and NGL prices, excluding hedging, reflected generally lower benchmark prices compared to 2013. Hedging activities contributed $4.32 per bbl to Encana's average realized oil price in 2014.

Financial Hedge Agreements

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 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.

During 2015, Encana entered into NYMEX and WTI three-way options and NYMEX costless collars. The three-way options are a combination of a sold call, bought put and a sold put. These contracts allow the Company to participate in the upside of commodity prices to the ceiling of the call option and provide the Company with partial downside price protection through the combination of the put options. The NYMEX costless collars are a combination of a sold call and a bought put. These contracts allow Encana to participate in the upside of commodity prices to the ceiling of the call option and provide downside price protection below the floor of the put option.

During 2016, Encana has entered into additional hedging agreements. The tables below summarize Encana's hedging contracts on expected future production as at December 31, 2015 and expected March to December 2016 production as at February 19, 2016.

Natural Gas

	As at February 19, 2016			As at December 31, 2015		
	Term	Notional Volumes (MMcf/d)	Average Price ($/Mcf)	Term	Notional Volumes (MMcf/d)	Average Price ($/Mcf)
NYMEX Fixed Price Contracts	**2016**	**740**	**2.76**	**2016**	**370**	**2.82**
NYMEX Fixed Price Swaptions [(1)]	**2017**	**345**	**2.70**	**-**	**-**	**-**
NYMEX Three-Way Options	**2017**	**255**		**2016**	**25**	
Sold call price			**3.07**			**3.43**
Bought put price			**2.75**			**3.21**
Sold put price			**2.26**			**2.72**
NYMEX Costless Collars	**2016**	**335**		**2016**	**335**	
Sold call price			**2.46**			**2.46**
Bought put price			**2.22**			**2.22**

(1) The NYMEX Fixed Price Swaptions give the counterparty the option to extend 2016 fixed price swaps to December 31, 2017 at the strike price.

Crude Oil

	As at February 19, 2016			As at December 31, 2015		
	Term	Notional Volumes (Mbbls/d)	Average Price ($/bbl)	Term	Notional Volumes (Mbbls/d)	Average Price ($/bbl)
WTI Fixed Price Contracts	**2016**	**54.1**	**56.33**	**2016**	**49.0**	**58.51**
WTI Three-Way Options	**2016**	**14.6**		**2016**	**18.3**	
Sold call price			**63.01**			**63.03**
Bought put price			**55.00**			**55.00**
Sold put price			**47.14**			**47.24**

The Company's hedging program helps sustain Cash Flow and Operating Netbacks during periods of lower prices. For additional information, see the Risk Management – Financial Risks section of this MD&A.

Foreign Exchange

As disclosed in the Prices and Foreign Exchange Rates table, the average U.S./Canadian dollar exchange rate decreased 0.123 in 2015 compared to 2014 and 0.066 in 2014 compared to 2013. The table below summarizes selected foreign exchange impacts on Encana's financial results when compared to the same periods in the prior years.

	2015		2014		2013	
	$ millions	$/BOE	$ millions	$/BOE	$ millions	$/BOE
Increase (Decrease) in:						
Capital Investment	**$ (168)**		$ (100)		$ (45)	
Transportation and Processing Expense [1]	**(111)**	**$ (0.75)**	(51)	$ (0.29)	(17)	$ (0.09)
Operating Expense [1]	**(36)**	**(0.24)**	(12)	(0.07)	(10)	(0.05)
Administrative Expense	**(24)**	**(0.16)**	(23)	(0.13)	(12)	(0.06)
Depreciation, Depletion and Amortization	**(84)**	**(0.57)**	(41)	(0.23)	(23)	(0.10)

(1) 2014 and 2013 have been updated to reflect the reclassification of property taxes and certain other levied charges from transportation and processing expense and/or operating expense to production, mineral and other taxes.

Price Sensitivities

Natural gas and liquids prices fluctuate in response to changing market forces, creating varying impacts on Encana's financial results. The Company's potential exposure to commodity price fluctuations is summarized in the table below, which shows the estimated effects that certain price changes would have had on the Company's Cash Flow and Operating Earnings (Loss) for 2015. The price sensitivities below are based on business conditions, transactions and production volumes during 2015. Accordingly, these sensitivities may not be indicative of financial results for other periods, under other economic circumstances or with additional fluctuations in commodity prices.

		Impact On	
($ millions, except as indicated)	Price Change [1]	Cash Flow	Operating Earnings (Loss)
Increase or Decrease in:			
NYMEX Natural Gas Price	+/- $0.50/MMBtu	**$ 25**	**$ 18**
WTI Oil Price	+/- $10.00/bbl	**30**	**20**

(1) Assumes only one variable changes while all other variables, including the Company's financial hedging positions, are held constant.

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 2015 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 barrels of oil equivalent. The conversion of natural gas volumes to BOE is on the basis of six Mcf to one bbl based on a generic energy equivalency conversion method primarily applicable at the burner tip. This energy equivalency conversion method does not represent economic value equivalency at the wellhead, 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 27 to the December 31, 2015 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. Encana's 2015 U.S. protocol disclosure is also available in the AIF.

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 [1]
(Forecast Prices and Costs; Before Royalties)

(as at December 31)	Natural Gas (Bcf) 2015	2014	2013	Oil & NGLs (MMbbls) 2015	2014	2013
Canada	**2,938**	3,752	5,031	**112.2**	97.2	141.1
United States	**1,646**	2,712	4,887	**366.6**	357.6	136.2
Total	**4,584**	6,463	9,918	**478.8**	454.7	277.3

(1) Numbers may not add due to rounding.

Proved Reserves Reconciliation [1]
(Forecast Prices and Costs; Before Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)			
	Canada	United States	Total	Canada	United States	Total	**Total** (MMBOE)
December 31, 2014	3,752	2,712	6,463	97.2	357.6	454.7	1,532.0
Extensions and improved recovery	460	154	614	39.9	96.4	136.2	238.5
Technical revisions	(157)	241	84	(4.3)	31.5	27.2	41.2
Economic factors	(274)	(244)	(518)	(6.8)	(64.4)	(71.2)	(157.5)
Dispositions	(459)	(923)	(1,382)	(2.0)	(5.7)	(7.7)	(238.1)
Production	(383)	(295)	(677)	(11.8)	(48.7)	(60.5)	(173.4)
December 31, 2015	**2,938**	**1,646**	**4,584**	**112.2**	**366.6**	**478.8**	**1,242.8**

(1) Numbers may not add due to rounding.

Encana's 2015 proved natural gas reserves before royalties of approximately 4.6 Tcf decreased 1.9 Tcf from 2014 primarily due to dispositions of approximately 1.4 Tcf resulting from the Company's strategic transition to a more balanced commodity portfolio. Extensions and improved recovery of approximately 0.6 Tcf were mostly offset by economic factors of approximately 0.5 Tcf due to a reduction in the forecast prices. Extensions and improved recovery replaced 91 percent of production before royalties during the year.

Encana's 2015 proved oil and NGL reserves before royalties of approximately 478.8 MMbbls increased 24.1 MMbbls from 2014 primarily due to extensions and improved recovery of approximately 136.2 MMbbls, partially offset by negative economic factors of approximately 71.2 MMbbls due to a reduction in the forecast prices. Extensions and improved recovery replaced 225 percent of production before royalties during the year.

Proved Reserves by Country [1]
(Forecast Prices and Costs; After Royalties)

(as at December 31)	Natural Gas (Bcf) 2015	2014	2013	Oil & NGLs (MMbbls) 2015	2014	2013
Canada	**2,666**	3,252	4,550	**91.5**	76.2	122.2
United States	**1,411**	2,270	4,026	**288.7**	280.3	112.7
Total	**4,076**	5,522	8,576	**380.1**	356.5	234.9

(1) Numbers may not add due to rounding.

Proved Reserves Reconciliation [1]
(Forecast Prices and Costs; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)			
	Canada	United States	Total	Canada	United States	Total	Total (MMBOE)
December 31, 2014	3,252	2,270	5,522	76.2	280.3	356.5	1,276.9
Extensions and discoveries	421	121	542	33.1	74.8	107.9	198.2
Revisions [2]	(224)	(4)	(228)	(5.8)	(23.3)	(29.1)	(67.1)
Dispositions	(430)	(734)	(1,164)	(1.7)	(4.8)	(6.5)	(200.5)
Production	(354)	(241)	(596)	(10.4)	(38.3)	(48.7)	(148.0)
December 31, 2015	**2,666**	**1,411**	**4,076**	**91.5**	**288.7**	**380.1**	**1,059.5**

(1) Numbers may not add due to rounding.
(2) Includes economic factors.

Encana's 2015 proved natural gas reserves after royalties of approximately 4.1 Tcf decreased 1.4 Tcf from 2014 primarily due to dispositions of approximately 1.2 Tcf resulting from the Company's strategic transition to a more balanced commodity portfolio. Negative revisions of approximately 0.2 Tcf were mainly due to negative economic factors of 0.4 Tcf offset by positive technical revisions of 0.2 Tcf. Extensions and discoveries replaced 91 percent of production after royalties during the year.

Encana's 2015 proved oil and NGL reserves after royalties of approximately 380.1 MMbbls increased 23.6 MMbbls from 2014 primarily due to extensions and discoveries of approximately 107.9 MMbbls. Extensions and discoveries replaced 222 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)
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
2014 Price Assumptions				
2015	3.31	3.31	62.50	64.71
2016 - 2024	3.75 - 5.68	3.77 - 5.71	75.00 - 104.57	80.00 - 112.67
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr
2015 Price Assumptions				
2016	**2.45**	**2.57**	**44.67**	**55.89**
2017 - 2030	**3.02 - 5.11**	**3.14 - 5.15**	**55.20 - 97.40**	**66.47 - 109.49**
Thereafter	**+1.8%/yr**	**+1.8%/yr**	**+1.8%/yr**	**+1.8%/yr**

U.S. Protocol Reserves Quantities

Proved Reserves by Country [1]
(12-month average trailing prices; After Royalties)

(as at December 31)	Natural Gas (Bcf)			Oil & NGLs (MMbbls)		
	2015	2014	2013	**2015**	2014	2013
Canada	**1,952**	3,229	3,975	**69.2**	77.5	110.2
United States	**1,112**	2,265	3,877	**219.7**	284.3	110.6
Total	**3,064**	5,494	7,852	**288.8**	361.7	220.8

(1) Numbers may not add due to rounding.

Proved Reserves Reconciliation [1]
(12-month average trailing prices; After Royalties)

	Natural Gas (Bcf)			Oil & NGLs (MMbbls)			
	Canada	United States	Total	Canada	United States	Total	**Total** (MMBOE)
December 31, 2014	3,229	2,265	5,494	77.5	284.3	361.7	1,277.4
Revisions and improved recovery	(801)	(342)	(1,144)	(15.8)	(114.7)	(130.5)	(321.1)
Extensions and discoveries	313	159	472	19.8	93.3	113.0	191.7
Sale of reserves in place	(434)	(728)	(1,163)	(1.9)	(4.8)	(6.8)	(200.6)
Production	(354)	(241)	(596)	(10.4)	(38.3)	(48.7)	(148.0)
December 31, 2015	**1,952**	**1,112**	**3,064**	**69.2**	**219.7**	**288.8**	**799.4**

(1) Numbers may not add due to rounding.

Encana's 2015 proved natural gas reserves after royalties of approximately 3.1 Tcf decreased 2.4 Tcf from 2014 primarily due to the sale of reserves in place of approximately 1.2 Tcf resulting from the Company's strategic transition to a more balanced commodity portfolio and approximately 1.1 Tcf due to a lower 12-month average trailing natural gas price. Extensions and discoveries of approximately 0.5 Tcf replaced 79 percent of production after royalties during the year.

Encana's 2015 proved oil and NGL reserves after royalties of approximately 288.8 MMbbls decreased 72.9 MMbbls from 2014 primarily due to reductions included in revisions and improved recovery of approximately 112.5 MMbbls due to lower 12-month average trailing oil and NGL prices. Extensions and discoveries of approximately 113.0 MMbbls replaced 232 percent of production after royalties during the year.

12-Month Average Trailing Prices

The reference prices below were utilized in the determination of reserves. The 12-month average trailing prices were 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]				
2013	3.67	3.14	96.94	93.44
2014	4.34	4.63	94.99	96.40
2015	**2.58**	**2.69**	**50.28**	**58.82**

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

Net Capital Investment

($ millions)	2015	2014	2013
Canadian Operations	**$ 380**	$ 1,226	$ 1,365
USA Operations	**1,847**	1,285	1,283
Market Optimization	**1**	-	3
Corporate & Other	**4**	15	61
Capital Investment	**2,232**	2,526	2,712
Acquisitions	**70**	3,016	184
Divestitures	**(1,908)**	(4,345)	(705)
Net Acquisitions & (Divestitures)	**(1,838)**	(1,329)	(521)
Net Capital Investment	**$ 394**	$ 1,197	$ 2,191

Capital Investment by Play

($ millions)	2015	2014	2013
Canadian Operations			
Montney [1]	**$ 159**	$ 781	$ 624
Duvernay	**205**	328	155
Other Upstream Operations			
Wheatland [2]	**5**	48	193
Bighorn	**-**	22	304
Deep Panuke	**4**	8	46
Other and emerging [1]	**7**	39	43
Total Canadian Operations	**$ 380**	$ 1,226	$ 1,365
USA Operations			
Eagle Ford	**$ 570**	$ 274	$ -
Permian	**916**	117	-
Other Upstream Operations			
DJ Basin	**169**	277	181
San Juan	**58**	287	166
Piceance	**12**	48	266
Haynesville	**34**	51	220
Jonah	**-**	25	58
East Texas	**-**	9	106
Other and emerging	**88**	197	286
Total USA Operations	**$ 1,847**	$ 1,285	$ 1,283
Capital Investment – Core Assets [1]	**$ 1,850**	$ 1,500	$ 779

(1) Montney has been realigned to include certain capital investments which were previously reported in Other and emerging.
(2) Wheatland was previously presented as Clearwater.

Encana's core assets include Montney, Duvernay, Eagle Ford and Permian and reflect the Company's focus on accelerating growth from these high return and scalable projects in the current price environment. Prior to 2015, Encana's growth assets included these core assets as well as the DJ Basin, San Juan and the Tuscaloosa Marine Shale ("TMS"), which is reported within Other and emerging in the USA Operations. As at December 31, 2015, the DJ Basin and San Juan have been realigned to Other Upstream Operations as a result of the Company's current capital investment strategy.

Capital investment associated with the Clearwater lands transferred to PrairieSky was included in Encana's Wheatland play until September 25, 2014, after which Encana no longer held an interest in PrairieSky.

2015

Capital Investment

Capital investment during 2015 was $2,232 million compared to $2,526 million in 2014 which reflected disciplined capital spending focused on the Company's core assets. During 2015, capital spending in Encana's core assets totaled $1,850 million, representing approximately 83 percent of 2015 capital investment.

Divestitures

Divestitures in 2015 were $959 million in the Canadian Operations and $896 million in the USA Operations, which primarily included the transactions discussed below, as well as the sale of certain properties that do not complement Encana's existing portfolio of assets.

The Canadian Operations included approximately C$557 million ($467 million), after closing adjustments, for the sale of the Company's working interest in certain assets included in Wheatland located in central and southern Alberta which comprised approximately 1.2 million net acres of land that contained over 6,800 producing wells. Encana retained a working interest in approximately 0.8 million net acres in Wheatland. In addition, the Canadian Operations included approximately C$450 million ($355 million), after closing adjustments, in cash consideration net to Encana for the sale of certain natural gas gathering and compression assets in Montney in northeastern British Columbia to VMLP. In conjunction with the sale, VMLP will undertake the expansion of future midstream services and will also provide natural gas gathering and processing in Montney to Encana and the Cutbank Ridge Partnership. Further information regarding VMLP can be found in Note 19 to the Consolidated Financial Statements.

The USA Operations included approximately $769 million, after closing adjustments, for the sale of the Company's Haynesville natural gas assets, comprising approximately 112,000 net acres of leasehold, plus additional fee mineral lands, located in northern Louisiana, to GeoSouthern.

2014

Capital Investment

Capital investment during 2014 was $2,526 million compared to $2,712 million in 2013. The Company's disciplined capital spending focused on the Company's growth assets as well as executing drilling programs with joint venture partners.

Acquisitions

Acquisitions in 2014 were $21 million in the Canadian Operations and $2,995 million in the USA Operations, which primarily included land and property purchases with oil and liquids rich production potential.

The USA Operations included approximately $2.9 billion, after closing adjustments, related to the acquisition of certain properties in the Eagle Ford shale formation in south Texas. Further information on the acquisition of Eagle Ford can be found in Note 3 to the Consolidated Financial Statements.

Divestitures

Divestitures in 2014 were $1,847 million in the Canadian Operations and $2,264 million in the USA Operations, which primarily included the sale of land and properties to balance the commodity mix in support of the Company's business strategy.

The Canadian Operations included approximately $1.7 billion, after closing adjustments, for the sale of the Company's Bighorn assets in west central Alberta. The USA Operations included approximately $1.6 billion, after closing adjustments, for the sale of the Jonah properties in Wyoming and approximately $495 million, after closing adjustments, for the sale of certain properties in East Texas.

Amounts received from the Company's divestiture transactions have been deducted from the respective Canadian and U.S. full cost pools, except for divestitures that resulted in a significant alteration between capitalized costs and proved reserves in the respective country cost centre. For divestitures that resulted in a gain or loss and constituted a business, goodwill was allocated to the divestiture. Accordingly, for the year ended December 31, 2014, Encana recognized a gain of approximately $1,014 million, before tax, on the sale of the Company's Bighorn assets in the Canadian cost centre and allocated goodwill of $257 million. In addition, for the year ended December 31, 2014, Encana recognized a gain of approximately $209 million, before tax, on the sale of the Jonah properties in the U.S. cost centre and allocated goodwill of $68 million.

Other Capital Transactions

The following transactions involved the acquisition or disposition of common shares and, therefore, are excluded from the Net Capital Investment table.

Acquisition of Athlon

On November 13, 2014, Encana completed the acquisition of all of the issued and outstanding shares of common stock of Athlon for $5.93 billion, or $58.50 per share. As part of the acquisition, Encana assumed Athlon's $1.15 billion senior notes and repaid and terminated Athlon's credit facility with indebtedness outstanding of $335 million. Athlon's operations focused on the acquisition and development of oil and gas properties located in the Permian Basin in west Texas. Further information on the acquisition of Athlon can be found in Note 3 to the Consolidated Financial Statements.

Divestiture of Investment in PrairieSky

During the second quarter of 2014, PrairieSky acquired Encana's royalty business with assets in Clearwater located predominantly in central and southern Alberta. Subsequently, Encana completed the initial public offering of 59.8 million common shares at a price of C$28.00 per common share for aggregate gross proceeds of approximately C$1.67 billion. Encana retained 70.2 million common shares of PrairieSky, representing a 54 percent ownership interest. For the period in which Encana held an ownership interest, the Company

consolidated the financial position and results of operations of PrairieSky and recognized a noncontrolling interest for the third party ownership.

On September 26, 2014, Encana completed the secondary offering of 70.2 million common shares of PrairieSky at a price of C$36.50 per common share for aggregate gross proceeds of approximately C$2.6 billion. Following the completion of the secondary offering, Encana no longer held an interest in PrairieSky. As the sale of the investment in PrairieSky resulted in a significant alteration between capitalized costs and proved reserves in the Canadian cost centre, Encana recognized a gain on divestiture of approximately $2.1 billion, before tax.

Further information on the PrairieSky transactions can be found in Note 18 to the Consolidated Financial Statements.

2013

Capital Investment

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 plays, investments in opportunities where development has demonstrated success and executing drilling programs with joint venture partners.

Acquisitions

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

Divestitures

Divestitures in 2013 were $685 million in the Canadian Operations and $18 million in the USA Operations. The Canadian Operations included the sale of the Company's Jean Marie natural gas assets in northeast British Columbia and other assets.

Production Volumes

(average daily, after royalties)	**2015**	2014	2013
Natural Gas (MMcf/d)	**1,635**	2,350	2,777
Oil (Mbbls/d)	**87.0**	49.4	25.8
NGLs (Mbbls/d)	**46.4**	37.4	28.1
Total Oil & NGLs (Mbbls/d)	**133.4**	86.8	53.9
Total Production (MBOE/d)	**405.9**	478.5	516.7
Production Mix (%)			
Natural Gas	**67**	82	90
Oil & NGLs	**33**	18	10

Production Volumes by Play

(average daily, after royalties)	Natural Gas (MMcf/d)			Oil & NGLs (Mbbls/d)		
	2015	2014	2013	**2015**	2014	2013
Canadian Operations						
Montney [(1)]	**723**	639	639	**22.5**	18.9	10.5
Duvernay	**27**	11	4	**4.8**	2.1	0.7
Other Upstream Operations						
Wheatland [(2)]	**86**	292	335	**0.9**	8.6	9.9
Bighorn	**1**	158	255	**-**	7.5	8.9
Deep Panuke	**63**	190	41	**-**	-	-
Other and emerging [(1)]	**71**	88	158	**0.2**	0.1	0.4
Total Canadian Operations	**971**	1,378	1,432	**28.4**	37.2	30.4
USA Operations						
Eagle Ford	**44**	19	-	**42.8**	19.8	-
Permian	**44**	5	-	**32.8**	3.5	-
Other Upstream Operations						
DJ Basin	**55**	43	39	**14.9**	11.6	8.4
San Juan	**13**	8	3	**6.2**	3.9	1.4
Piceance	**320**	402	455	**3.5**	5.0	5.1
Haynesville	**173**	311	348	**-**	-	-
Jonah	**-**	100	323	**-**	1.8	4.7
East Texas	**-**	57	136	**-**	0.5	1.0
Other and emerging	**15**	27	41	**4.8**	3.5	2.9
Total USA Operations	**664**	972	1,345	**105.0**	49.6	23.5
Total Production Volumes	**1,635**	2,350	2,777	**133.4**	86.8	53.9
Total Production Volumes – Core Assets [(1)]	**838**	674	643	**102.9**	44.3	11.2

(1) Montney has been realigned to include certain production volumes which were previously reported in Other and emerging.
(2) Wheatland was previously presented as Clearwater.

Encana's core assets include Montney, Duvernay, Eagle Ford and Permian and reflect the Company's focus on accelerating growth from these high return and scalable projects in the current price environment. Prior to 2015, Encana's growth assets included these core assets as well as the DJ Basin, San Juan and the TMS, which is reported within Other and emerging in the USA Operations. As at December 31, 2015, the DJ Basin and San Juan have been realigned to Other Upstream Operations as a result of the Company's current capital investment strategy.

The production volumes associated with the Clearwater lands transferred to PrairieSky were included in Encana's Wheatland play until September 25, 2014, after which Encana no longer held an interest in PrairieSky.

2015 versus 2014

Natural Gas Production Volumes

In 2015, average natural gas production volumes of 1,635 MMcf/d decreased 715 MMcf/d from 2014. The Canadian Operations volumes were lower primarily due to the sale of certain assets included in Wheatland in January 2015, the sale of the Bighorn assets in the third quarter of 2014 and shut-in production at Deep Panuke as a result of the implementation of a seasonal operating strategy in 2015 and a higher water production rate, partially offset by successful drilling programs in Montney and Duvernay. The USA Operations volumes were lower primarily due to natural declines in Haynesville and Piceance and the sales of the Jonah and East Texas properties in the second quarter of 2014.

Oil and NGL Production Volumes

In 2015, average oil and NGL production volumes of 133.4 Mbbls/d increased 46.6 Mbbls/d from 2014. The USA Operations volumes were higher primarily due to the acquisitions of Eagle Ford and the Permian assets in the second and fourth quarters of 2014, respectively, and successful drilling programs in these plays. The Canadian Operations volumes were lower primarily due to the sales of the Bighorn assets and the Company's investment in PrairieSky in the third quarter of 2014, partially offset by successful drilling programs in Montney and Duvernay.

2014 versus 2013

Natural Gas Production Volumes

In 2014, average natural gas production volumes of 2,350 MMcf/d decreased 427 MMcf/d from 2013. The Canadian Operations volumes were lower in 2014 primarily due to the sale of the Bighorn assets, the sale of the Jean Marie natural gas assets and natural declines, partially offset by higher production volumes from Deep Panuke and a successful drilling program in Montney. The USA Operations volumes were lower in 2014 primarily due to the sale of the Jonah and East Texas properties and natural declines mainly in Piceance and Haynesville.

Oil and NGL Production Volumes

In 2014, average oil and NGL production volumes of 86.8 Mbbls/d increased 32.9 Mbbls/d from 2013. The Canadian Operations volumes were higher in 2014 primarily due to successful drilling programs, mainly in Montney, partially offset by the sale of the Bighorn assets. The Canadian Operations volumes were also impacted by the sale of the Company's investment in PrairieSky, partially offset by higher royalty volumes in Clearwater associated with the lands transferred to PrairieSky. The USA Operations volumes were higher in 2014 primarily due to the acquisition of Eagle Ford and the Permian assets and successful drilling programs in the DJ Basin and San Juan, partially offset by the sale of the Jonah properties.

Results of Operations

Canadian Operations

Operating Cash Flow [1]

($ millions)	Natural Gas 2015	Natural Gas 2014	Natural Gas 2013	Oil & NGLs 2015	Oil & NGLs 2014	Oil & NGLs 2013	Total [2] 2015	Total [2] 2014	Total [2] 2013
Revenues, Net of Royalties, excluding Hedging	**$ 976**	$ 2,468	$ 1,771	**$ 333**	$ 872	$ 722	**$ 1,327**	$ 3,366	$ 2,548
Realized Financial Hedging Gain (Loss)	**479**	(74)	271	**16**	18	5	**495**	(56)	276
Revenues, Net of Royalties	**1,455**	2,394	2,042	**349**	890	727	**1,822**	3,310	2,824
Expenses									
Production, mineral and other taxes	**26**	53	48	**2**	11	12	**28**	64	60
Transportation and processing	**605**	764	715	**49**	62	32	**654**	826	747
Operating	**135**	240	287	**15**	27	38	**152**	274	336
Operating Cash Flow	**$ 689**	$ 1,337	$ 992	**$ 283**	$ 790	$ 645	**$ 988**	$ 2,146	$ 1,681

Production Volumes

	Natural Gas (MMcf/d) 2015	Natural Gas (MMcf/d) 2014	Natural Gas (MMcf/d) 2013	Oil & NGLs (Mbbls/d) 2015	Oil & NGLs (Mbbls/d) 2014	Oil & NGLs (Mbbls/d) 2013	Total (MBOE/d) 2015	Total (MBOE/d) 2014	Total (MBOE/d) 2013
Production Volumes – After Royalties	**971**	1,378	1,432	**28.4**	37.2	30.4	**190.2**	266.9	269.0

Operating Netback [1], [3]

	Natural Gas ($/Mcf) 2015	Natural Gas ($/Mcf) 2014	Natural Gas ($/Mcf) 2013	Oil & NGLs ($/bbl) 2015	Oil & NGLs ($/bbl) 2014	Oil & NGLs ($/bbl) 2013	Total ($/BOE) 2015	Total ($/BOE) 2014	Total ($/BOE) 2013
Revenues, Net of Royalties, excluding Hedging	**$ 2.75**	$ 4.89	$ 3.35	**$ 32.10**	$ 64.16	$ 65.06	**$ 18.84**	$ 34.21	$ 25.13
Realized Financial Hedging Gain (Loss)	**1.35**	(0.15)	0.51	**1.56**	1.36	0.46	**7.13**	(0.57)	2.78
Revenues, Net of Royalties	**4.10**	4.74	3.86	**33.66**	65.52	65.52	**25.97**	33.64	27.91
Expenses									
Production, mineral and other taxes	**0.07**	0.11	0.09	**0.18**	0.85	1.05	**0.41**	0.66	0.61
Transportation and processing	**1.71**	1.50	1.36	**4.71**	4.49	2.88	**9.42**	8.45	7.52
Operating	**0.38**	0.48	0.54	**1.48**	1.98	3.48	**2.17**	2.73	3.29
Operating Netback	**$ 1.94**	$ 2.65	$ 1.87	**$ 27.29**	$ 58.20	$ 58.11	**$ 13.97**	$ 21.80	$ 16.49

(1) Updated to reflect the reclassification of property taxes and certain other levied charges as discussed below.
(2) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(3) A Non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Comparative figures for 2014 and 2013 above have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Formerly, these costs were presented in either transportation and processing expense or operating expense. As a result, for 2014, the Canadian Operations has reclassified $9 million from transportation and processing expense and $40 million from operating expense to production, mineral and other taxes. For 2013, the Canadian Operations has reclassified $9 million from transportation and processing expense and $36 million from operating expense to production, mineral and other taxes. There were no changes to the reported totals for Operating Cash Flow or Operating Netback.

2015 versus 2014

Operating Cash Flow of $988 million decreased $1,158 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $759 million. The average realized natural gas price for production from Deep Panuke was $8.19 per Mcf compared to $8.34 per Mcf in 2014 and increased the average realized natural gas price $0.37 per Mcf compared to $0.54 per Mcf in 2014. Lower liquids prices reflected lower benchmark prices, which decreased revenues $332 million.
- Average natural gas production volumes of 971 MMcf/d were lower by 407 MMcf/d, which decreased revenues $733 million. Average oil and NGL production volumes of 28.4 Mbbls/d were lower by 8.8 Mbbls/d, which decreased revenues $207 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $495 million compared to losses of $56 million in 2014.
- Transportation and processing expense decreased $172 million primarily due to the sale of the Bighorn assets in the third quarter of 2014, the lower U.S./Canadian dollar exchange rate, the sale of certain assets included in Wheatland in January 2015, and shut-in production at Deep Panuke as a result of the implementation of a seasonal operating strategy in 2015 and a higher water production rate, partially offset by higher volumes in Montney.
- Operating expense decreased $122 million primarily due to the sale of certain assets included in Wheatland in January 2015, the lower U.S./Canadian dollar exchange rate, the sale of the Bighorn assets in the third quarter of 2014 and lower long-term compensation costs due to the decrease in the Encana share price.

2014 versus 2013

Operating Cash Flow of $2,146 million increased $465 million and was impacted by the following significant items:

- Higher natural gas prices reflected higher benchmark prices. Realized natural gas prices for production from Deep Panuke were $8.34 per Mcf which increased the average realized natural gas price $0.54 per Mcf. Higher realized natural gas prices for production, including Deep Panuke, increased revenues $780 million. Lower liquids prices decreased revenues $13 million.
- Average natural gas production volumes of 1,378 MMcf/d were lower by 54 MMcf/d, which decreased revenues $83 million. Average oil and NGL production volumes of 37.2 Mbbls/d were higher by 6.8 Mbbls/d, which increased revenues $163 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging losses were $56 million compared to gains of $276 million in 2013.
- Transportation and processing expense increased $79 million primarily due to costs related to Deep Panuke production and higher liquids volumes processed, partially offset by the lower U.S./Canadian dollar exchange rate and the sale of the Bighorn assets. The Deep Panuke offshore natural gas facility commenced commercial operations in December 2013.
- Operating expense decreased $62 million primarily due to lower salaries and benefits related to workforce reductions as a result of the 2013 restructuring, the lower U.S./Canadian dollar exchange rate, the sale of the Bighorn assets, the sale of the Jean Marie natural gas assets in the second quarter of 2013 and lower long-term compensation costs due to the decrease in the Encana share price.

Other Expenses

($ millions, except as indicated)		2015		2014		2013
Depreciation, depletion & amortization	**$**	**305**	$	625	$	601
Depletion rate ($/BOE)		**4.39**		6.40		6.06

DD&A decreased in 2015 compared to 2014 primarily due to lower production volumes, a lower depletion rate and the lower U.S./Canadian dollar exchange rate. The depletion rate was impacted by the sales of the Bighorn assets and the Company's investment in PrairieSky in the third quarter of 2014 and the lower U.S./Canadian dollar exchange rate.

DD&A increased in 2014 compared to 2013 primarily due to a higher depletion rate, partially offset by the lower U.S./Canadian dollar exchange rate. The depletion rate was impacted by the sale of the Bighorn assets, the sale of the Company's investment in PrairieSky, a decline in proved reserves due to Encana's change in development plans as the Company strategically transitioned to a more balanced commodity portfolio and the lower U.S./Canadian dollar exchange rate.

USA Operations

Operating Cash Flow [1]

($ millions)	Natural Gas 2015	2014	2013	Oil & NGLs 2015	2014	2013	Total [2] 2015	2014	2013
Revenues, Net of Royalties, excluding Hedging	**$ 629**	$ 1,640	$ 1,872	**$ 1,412**	$ 1,258	$ 602	**$2,066**	$ 2,927	$ 2,499
Realized Financial Hedging Gain (Loss)	**239**	(85)	260	**185**	60	4	**425**	(25)	264
Revenues, Net of Royalties	**868**	1,555	2,132	**1,597**	1,318	606	**2,491**	2,902	2,763
Expenses									
Production, mineral and other taxes	**27**	57	72	**89**	89	41	**116**	146	113
Transportation and processing	**566**	651	722	**14**	7	-	**580**	658	722
Operating	**158**	222	344	**357**	100	60	**519**	326	417
Operating Cash Flow	**$ 117**	$ 625	$ 994	**$ 1,137**	$ 1,122	$ 505	**$ 1,276**	$ 1,772	$ 1,511

Production Volumes

	Natural Gas (MMcf/d) 2015	2014	2013	Oil & NGLs (Mbbls/d) 2015	2014	2013	Total (MBOE/d) 2015	2014	2013
Production Volumes – After Royalties	**664**	972	1,345	**105.0**	49.6	23.5	**215.7**	211.6	247.7

Operating Netback [1], [3]

	Natural Gas ($/Mcf) 2015	2014	2013	Oil & NGLs ($/bbl) 2015	2014	2013	Total ($/BOE) 2015	2014	2013
Revenues, Net of Royalties, excluding Hedging	**$ 2.60**	$ 4.62	$ 3.81	**$ 36.80**	$ 69.54	$ 70.18	**$ 25.93**	$ 37.53	$ 27.37
Realized Financial Hedging Gain (Loss)	**0.99**	(0.24)	0.53	**4.83**	3.29	0.44	**5.39**	(0.33)	2.93
Revenues, Net of Royalties	**3.59**	4.38	4.34	**41.63**	72.83	70.62	**31.32**	37.20	30.30
Expenses									
Production, mineral and other taxes	**0.11**	0.16	0.15	**2.30**	4.93	4.71	**1.47**	1.89	1.25
Transportation and processing	**2.34**	1.82	1.47	**0.35**	0.39	-	**7.37**	8.51	7.98
Operating	**0.65**	0.63	0.70	**9.33**	5.53	7.10	**6.55**	4.18	4.48
Operating Netback	**$ 0.49**	$ 1.77	$ 2.02	**$ 29.65**	$ 61.98	$ 58.81	**$ 15.93**	$ 22.62	$ 16.59

(1) Updated to reflect the reclassification of property taxes and certain other levied charges as discussed below.
(2) Also includes other revenues and expenses, such as third party processing, with no associated volumes.
(3) A Non-GAAP measure as defined in the Non-GAAP Measures section of this MD&A.

Comparative figures for 2014 and 2013 above have been updated to present property taxes and certain other levied charges within production, mineral and other taxes. Formerly, these costs were presented in either transportation and processing expense or operating expense. As a result, for 2014, the USA Operations has reclassified $28 million from operating expense to production, mineral and other taxes. For 2013, the USA Operations has reclassified $6 million from operating expense to production, mineral and other taxes. There were no changes to the reported totals for Operating Cash Flow or Operating Netback.

2015 versus 2014

Operating Cash Flow of $1,276 million decreased $496 million and was impacted by the following significant items:

- Lower natural gas prices reflected lower benchmark prices, which decreased revenues $439 million. Lower liquids prices reflected lower benchmark prices, which decreased revenues $819 million.
- Average natural gas production volumes of 664 MMcf/d were lower by 308 MMcf/d, which decreased revenues $572 million. Average oil and NGL production volumes of 105.0 Mbbls/d were higher by 55.4 Mbbls/d, which increased revenues $973 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging gains were $425 million compared to losses of $25 million in 2014.
- Transportation and processing expense decreased $78 million primarily due to divestitures, which includes the sales of the Jonah and East Texas properties in the second quarter of 2014, partially offset by the acquisitions of Eagle Ford and the Permian assets in the second and fourth quarters of 2014, respectively.
- Operating expense increased $193 million primarily due to the acquisitions of Eagle Ford and the Permian assets in the second and fourth quarters of 2014, respectively, and successful drilling programs in these plays during 2015, partially offset by the sales of the Jonah and East Texas properties in the second quarter of 2014.

2014 versus 2013

Operating Cash Flow of $1,772 million increased $261 million and was impacted by the following significant items:

- Higher natural gas prices reflected higher benchmark prices, which increased revenues $287 million. Lower liquids prices decreased revenues $10 million.
- Average natural gas production volumes of 972 MMcf/d were lower by 373 MMcf/d, which decreased revenues $519 million. Average oil and NGL production volumes of 49.6 Mbbls/d were higher by 26.1 Mbbls/d, which increased revenues $666 million. Changes in production volumes are discussed in the Production Volumes section of this MD&A.
- Realized financial hedging losses were $25 million compared to gains of $264 million in 2013.
- Transportation and processing expense decreased $64 million primarily due to the sale of the Jonah and East Texas properties.
- Operating expense decreased $91 million primarily due to lower salaries and benefits related to workforce reductions as a result of the 2013 restructuring, the sale of the Jonah properties and lower long-term compensation costs due to the decrease in the Encana share price, partially offset by the acquisition of Eagle Ford and the Permian assets.

Other Expenses

($ millions, except as indicated)		**2015**		2014		2013
Depreciation, depletion & amortization	**$**	**1,088**	$	992	$	818
Depletion rate ($/BOE)		**13.66**		12.85		9.05
Impairments		**6,473**		-		-

DD&A increased in 2015 compared to 2014 primarily due to a higher depletion rate and higher production volumes. The depletion rate was higher primarily due to the acquisitions of Eagle Ford and the Permian assets in the second and fourth quarters of 2014, respectively, partially offset by the impact of ceiling test impairments recognized in the first nine months of 2015 and the sales of the Haynesville natural gas assets and Jonah properties in the fourth quarter of 2015 and second quarter of 2014, respectively.

DD&A increased in 2014 compared to 2013 due to a higher depletion rate, partially offset by lower production volumes. The higher depletion rate in 2014 resulted primarily from the acquisition of Eagle Ford and the Permian assets, the sale of the Jonah properties and a decline in proved reserves due to Encana's change in development plans as the Company strategically transitioned to a more balanced commodity portfolio.

In 2015, the USA Operations recognized before-tax non-cash ceiling test impairments of $6,473 million. The impairments primarily resulted from the decline in the 12-month average trailing prices, which reduced the USA Operations proved reserves volumes and values as calculated under SEC requirements.

Market Optimization

($ millions)	2015	2014	2013
Revenues	$ 365	$ 1,248	$ 512
Expenses			
Transportation and processing	12	-	-
Operating	33	39	38
Purchased product	323	1,191	441
Depreciation, depletion and amortization	-	4	12
	$ (3)	$ 14	$ 21

Market Optimization revenues and purchased product expense relate to activities that provide operational flexibility and cost mitigation for transportation commitments, product type, delivery points and customer diversification. Revenues and purchased product expense decreased in 2015 compared to 2014 primarily due to lower commodity prices and lower third-party volumes resulting from transitional services related to the Company's divestiture activity. Transportation and processing in 2015 relates to downstream transportation contracts and commitments as a result of the Company's property divestitures. Revenues and purchased product expense increased in 2014 compared to 2013 primarily due to generally higher commodity prices, and higher third party purchases and sales of product resulting from transitional services related to the Company's divestiture activity.

Corporate and Other

($ millions)	2015	2014	2013
Revenues	$ (256)	$ 559	$ (241)
Expenses			
Transportation and processing	6	12	(2)
Operating	19	28	38
Depreciation, depletion and amortization	95	124	134
Impairments	-	-	21
	$ (376)	$ 395	$ (432)

Revenues mainly includes 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. Further information on The Bow office sublease can be found in Note 14 to the Consolidated Financial Statements.

Other Operating Results

Expenses

($ millions)	2015	2014	2013
Accretion of asset retirement obligation	**$ 45**	$ 52	$ 53
Administrative	**275**	327	439
Interest	**614**	654	563
Foreign exchange (gain) loss, net	**1,082**	403	325
(Gain) loss on divestitures	**(14)**	(3,426)	(7)
Other	**27**	71	1
	$ 2,029	$ (1,919)	$ 1,374

Administrative expense in 2015 decreased from 2014 primarily due to the lower U.S./Canadian dollar exchange rate, lower salaries and benefits as a result of lower headcount and lower long-term compensation costs due to the decrease in the Encana share price, partially offset by higher restructuring costs. During the second quarter of 2015, Encana revised its plans to align the organizational structure in continued support of the Company's strategy, which resulted in restructuring costs of $62 million in 2015. Restructuring costs attributable to work force reductions associated with the 2013 restructuring were $2 million in 2015. Administrative expense in 2014 decreased from 2013 primarily due to lower restructuring costs, lower long-term compensation costs and the lower U.S./Canadian dollar exchange rate. Restructuring costs incurred in 2014 were approximately $36 million compared to $88 million in 2013.

Interest expense in 2015 decreased from 2014 primarily due to lower interest on debt following the April 2015 early debt redemptions. Interest expense was also impacted by a one-time interest payment of approximately $165 million associated with the April 2015 redemptions compared to a $125 million one-time outlay in 2014 associated with the early redemption of senior notes assumed in conjunction with the acquisition of Athlon. Interest expense in 2014 increased from 2013 primarily due to the one-time outlay of approximately $125 million associated with the redemption of the Athlon senior notes and higher interest related to the Deep Panuke Production Field Centre ("PFC"), partially offset by lower interest on debt resulting from the long-term debt repayment and redemption in the first six months of 2014.

Foreign exchange gains and losses result from the impact of the fluctuations in the Canadian to U.S. dollar exchange rate. In 2015 compared to 2014, Encana recorded higher foreign exchange losses on settlements and on the translation of U.S. dollar long-term debt issued from Canada. In 2014 compared to 2013, Encana recorded higher foreign exchange losses on the translation of U.S. dollar long-term debt issued from Canada.

Gain on divestitures in 2015 primarily includes a before tax gain on the sale of the Encana Place office building in Calgary. Gain on divestitures in 2014 primarily includes the before tax impact of the sales of Encana's investment in PrairieSky, the Bighorn assets and the Jonah properties, as discussed in the Net Capital Investment section of this MD&A.

Other in 2015 decreased from 2014 due to transaction costs associated with the acquisitions of Athlon and Eagle Ford incurred in 2014. Other in 2014 increased from 2013 due to acquisition transaction costs as well as reclamation charges relating to non-producing assets.

Income Tax

($ millions)	2015	2014	2013
Current Income Tax (Recovery)	**$ (34)**	$ 243	$ (191)
Deferred Income Tax (Recovery)	**(2,811)**	960	(57)
Income Tax Expense (Recovery)	**$ (2,845)**	$ 1,203	$ (248)

The current income tax recovery of $34 million in 2015 was primarily due to amounts in respect of prior periods. The current income tax expense in 2014 was primarily due to taxes incurred on divestitures. The current income tax recovery in 2013 was primarily due to amounts in respect of prior periods.

Total income tax recovery of $2,845 million in 2015 was primarily due to lower net earnings before tax, mainly resulting from non-cash ceiling test impairments. Total income tax was an expense in 2014 due to higher net earnings before tax primarily from gains on divestitures and unrealized hedging gains. Total income tax was a recovery in 2013 primarily due to amounts in respect of prior periods. The net earnings variances are 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)	2015	2014	2013
Net Cash From (Used In)			
Operating activities	**$ 1,681**	$ 2,667	$ 2,289
Investing activities	**(665)**	(4,729)	(1,895)
Financing activities	**(1,054)**	(39)	(909)
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency	**(29)**	(127)	(98)
Increase (Decrease) in Cash and Cash Equivalents	**$ (67)**	$ (2,228)	$ (613)
Cash and Cash Equivalents, End of Year	**$ 271**	$ 338	$ 2,566

Operating Activities

Net cash from operating activities in 2015 of $1,681 million decreased $986 million from 2014. Net cash from operating activities in 2014 of $2,667 million increased $378 million from 2013. These changes are primarily a result of the Cash Flow variances discussed in the Financial Results section of this MD&A. In 2015, the net change in non-cash working capital was a surplus of $262 million compared to a deficit of $9 million in 2014 and a deficit of $179 million in 2013.

The Company had a working capital surplus of $274 million at December 31, 2015 compared to $583 million at December 31, 2014. The decrease in working capital is primarily due to a decrease in accounts receivable and accrued revenues, risk management assets and income tax receivable, partially offset by a decrease in accounts payable and accrued liabilities. At December 31, 2015, working capital included cash and cash equivalents of $271 million compared to $338 million at December 31, 2014. Encana expects it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used in investing activities in 2015 was $665 million compared to $4,729 million in 2014. The change was primarily due to the acquisitions of Athlon and Eagle Ford in 2014, partially offset by lower proceeds from divestitures and the sale of the Company’s investment in PrairieSky in 2014. Net cash used in investing activities in 2014 was $4,729 million compared to $1,895 million in 2013. The increase was primarily due to the acquisitions of Athlon and Eagle Ford, partially offset by proceeds from the Bighorn, Jonah and East Texas divestitures and proceeds from the sale of the Company’s investment in PrairieSky. Further information on acquisitions and divestitures can be found in the Net Capital Investment section of this MD&A.

Financing Activities

Net cash used in financing activities in 2015 was $1,054 million compared to $39 million in 2014. The change was primarily due to a net repayment of revolving long-term debt of $627 million in 2015 compared with a net issuance in 2014 of $942 million, and the sale of a noncontrolling interest in PrairieSky in the second quarter of 2014 for proceeds of $1,462 million, partially offset by proceeds of $1,088 million from the issuance of common shares pursuant to the Share Offering in the first quarter of 2015 and lower long-term debt repayments in 2015 of $850 million. Net cash used in financing activities in 2014 was $39 million compared to $909 million in 2013. The decrease primarily resulted from the sale of a noncontrolling interest in PrairieSky and the net issuance of revolving long-term debt, partially offset by the repayment of long-term debt.

Credit Facilities

The following table outlines the Company's committed revolving bank credit facilities at December 31, 2015:

($ billions)	Capacity	Unused	Maturity Date
Committed Revolving Bank Credit Facilities			
Encana Credit Facility [(1)]	**3.0**	**2.4**	**July 2020**
U.S. Subsidiary Credit Facility	**1.5**	**1.5**	**July 2020**

(1) At December 31, 2015, $440 million fully supported the U.S. Commercial Paper program and $210 million of LIBOR loans were drawn, as discussed in the Long-Term Debt section below.

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 requires 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 28 percent at December 31, 2015 and 30 percent at December 31, 2014.

Management believes that the downgrade in Encana's credit rating by Moody's Investors Service on February 18, 2016, along with recently confirmed investment grade credit ratings by Standard & Poor's Ratings Services and DBRS Limited, will have limited implications for the Company's ability to fund its operations, development activities and capital program. The split ratings eliminates the Company's access to its U.S. Commercial Paper ("U.S. CP") program; however, the Company continues to have full access to its $4.5 billion committed revolving bank credit facilities of which $3.9 billion remained unused at December 31, 2015. The facilities remain committed through July 2020. The cost of short-term borrowing on the Company's credit facilities will increase modestly as a result of the split ratings. For further information on credit ratings, refer to the Company's AIF.

Long-Term Debt

Encana's long-term debt totaled $5,363 million at December 31, 2015 and $7,340 million at December 31, 2014. There was no current portion of long-term debt outstanding at December 31, 2015 or December 31, 2014.

On April 6, 2015, the Company used the net proceeds from the Share Offering and cash on hand to complete the redemption of its $700 million 5.90 percent notes due December 1, 2017 and its C$750 million 5.80 percent medium-term notes due January 18, 2018. The early note redemptions required an aggregate one-time interest payment of approximately $165 million and is expected to save Encana a gross amount of approximately $205 million in future interest expense, based on foreign exchange and treasury rates at the time of the redemptions.

During the first quarter of 2015, Encana implemented a U.S. CP program which is fully supported by the Company's revolving credit facility. At December 31, 2015, Encana had an outstanding balance of $440 million which reflected U.S. CP issuances maturing at various dates with a weighted average interest rate of 1.13 percent. At December 31, 2015, Encana also had an outstanding balance of $210 million under the Company's revolving credit facility which reflected principal obligations related to LIBOR loans maturing at various dates with

a weighted average interest rate of 1.87 percent. These amounts are fully supported and Management expects they will continue to be supported by the revolving credit facility that has no repayment requirements within the next year.

At December 31, 2014, Encana had an outstanding balance of $1,277 million under the Company's revolving credit facility, which reflected principal obligations related to LIBOR loans maturing at various dates with a weighted average interest rate of 1.62 percent. During the first quarter of 2015, Encana repaid the outstanding balance relating to LIBOR loans using proceeds from the U.S. CP program and cash on hand.

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.

Shelf Prospectus

On June 27, 2014, Encana filed a short form base shelf prospectus, whereby the Company may issue from time to time up to $6.0 billion, or the equivalent in foreign currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants and units in Canada and/or the U.S. On March 5, 2015, the Company filed a prospectus supplement to the base shelf prospectus for the issuance of 85,616,500 common shares of Encana and granted an over-allotment option for up to an additional 12,842,475 common shares of Encana at a price of C$14.60 per common share, pursuant to an underwriting agreement. The Share Offering of 98,458,975 common shares of Encana was completed during March 2015 for aggregate gross proceeds of approximately C$1.44 billion ($1.13 billion). After deducting underwriter's fees and costs of the Share Offering, the net proceeds received were approximately C$1.39 billion ($1.09 billion). At December 31, 2015, $4.9 billion, or the equivalent in foreign currencies, remained accessible under the shelf prospectus, the availability of which is dependent upon market conditions. The shelf prospectus expires in July 2016.

Outstanding Share Data

(millions)	**February 19, 2016**	**December 31, 2015**	December 31, 2014
Common Shares Outstanding	**849.8**	**849.8**	741.2
Stock Options with Tandem Stock Appreciation Rights attached			
Outstanding	**16.3**	**18.3**	21.3
Exercisable	**11.5**	**10.0**	10.0

During the first quarter of 2015, Encana issued common shares pursuant to the Share Offering as discussed above.

During 2015, Encana issued 10,246,221 common shares under the Company's dividend reinvestment plan ("DRIP") compared with 240,839 common shares in 2014. The number of common shares issued under the DRIP increased in 2015 primarily as a result of Encana's February 25, 2015 announcement that, effective with the dividend payable on March 31, 2015, any dividends in conjunction with the DRIP would be issued from its treasury with a two percent discount to the average market price of the common shares. On December 14, 2015, the Company announced that any dividends subsequent to December 31, 2015 distributed to shareholders participating in the DRIP will be issued from its treasury without a discount to the average market price of the common shares unless otherwise announced by the Company via news release.

Eligible employees have been granted stock options to purchase common shares in accordance with Encana's Employee Stock Option Plan. A Tandem Stock Appreciation Right ("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. Historically, most holders of these options have elected to exercise their stock options as a TSAR in exchange for a cash payment. 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.

Dividends

Encana pays quarterly dividends to shareholders at the discretion of the Board.

($ millions, except as indicated)	2015	2014
Dividend Payments	$ 225	$ 207
Dividend Payments ($/share)	0.28	0.28

The dividends paid in 2015 included $73 million in common shares issued in lieu of cash dividends under the DRIP compared to $5 million for 2014. Common shares issued in the Share Offering were not eligible to receive the dividend that was paid during the first quarter of 2015. On December 14, 2015, the Company announced that it planned to reset its annualized 2016 dividend to $0.06 per share.

On February 23, 2016, the Board declared a dividend of $0.015 per share payable on March 31, 2016 to common shareholders of record as of March 15, 2016.

Capital Structure

The Company's capital structure consists of total 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 the following non-GAAP financial metrics as indicators of its overall financial strength, which are defined in the Non-GAAP Measures section of this MD&A.

	2015	2014	2013
Debt to Debt Adjusted Cash Flow	2.8x	2.1x	2.4x
Debt to Adjusted Capitalization	28%	30%	36%

Contractual Obligations and Contingencies

Commitments

The following table outlines the Company's commitments at December 31, 2015:

	Expected Future Payments						
($ millions, undiscounted)	2016	2017	2018	2019	2020	Thereafter	Total
Long-Term Debt [(1)]	$ -	$ -	$ -	$ 500	$ 650	$ 4,200	**$ 5,350**
Asset Retirement Obligation	42	58	96	105	24	2,251	**2,576**
Other Long-Term Obligations	68	68	69	69	70	1,315	**1,659**
Capital Leases	98	99	99	99	99	133	**627**
Obligations [(2)]	208	225	264	773	843	7,899	**10,212**
Transportation and Processing	693	679	685	588	491	2,507	**5,643**
Drilling and Field Services	164	106	59	29	17	1	**376**
Operating Leases	30	24	23	11	3	19	**110**
Commitments	887	809	767	628	511	2,527	**6,129**
Total Contractual Obligations	$ 1,095	$ 1,034	$ 1,031	$ 1,401	$ 1,354	$10,426	**$16,341**
Sublease Recoveries	$ (34)	$ (34)	$ (34)	$ (34)	$ (34)	$ (646)	**$ (816)**

(1) Principal component only. See Note 13 to the Consolidated Financial Statements.
(2) The Company has recorded $7,818 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 $1,659 million, of which $816 million is expected to be recovered from Cenovus.

Capital Leases primarily includes the obligation related to the Deep Panuke PFC, which commenced commercial operations in December 2013 following issuance of the Production Acceptance Notice. Encana's undiscounted future lease payments for the Deep Panuke PFC total $534 million ($340 million discounted).

Included in Transportation and Processing in the table above are certain commitments associated with midstream service agreements with VMLP. Additional information can be found in Note 19 to the Consolidated Financial Statements. Encana also 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. Additional information can be found in the note disclosures to the Consolidated Financial Statements.

Divestiture transactions can reduce certain commitments and obligations disclosed above. The Company expects to fund its 2016 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 operations 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 aims to strengthen its position as a leading North American energy producer and grow shareholder value through a disciplined focus on generating profitable growth. Encana continues to focus on developing a balanced portfolio of low-risk and low-cost long-life plays, enabling the Company to respond 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 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 risks.

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. 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 in order to support capital plans and strategic objectives.

To partially mitigate commodity price risk, the Company may enter into transactions that fix, set a floor or combine to set floors and caps on price exposures. 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, 2015, is disclosed in Note 24 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. Credit exposures are managed 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 as well as debt and equity 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 may also maintain a mix of both U.S. dollar and Canadian dollar debt to help offset 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 partially mitigates 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 price volatility mentioned above, continued market demand for its products and other 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; partner funding for their share of joint venture and partnership commitments; the availability of drilling and other equipment; the ability to retain leases and access lands; the ability to access water for hydraulic fracturing operations; weather; the availability and proximity of processing and pipeline capacity; transportation interruption and constraints; technology failures; the ability to assess and integrate new assets; cyber security breaches; accidents; the availability and ability to attract qualified personnel and service providers; type curve performance; 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, engineering risk and reliance on third party service providers.

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.

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

When making operating and investing decisions, Encana's highly disciplined, dynamic and centrally controlled capital allocation program ensures investment dollars are directed in a manner that is consistent with the Company's strategy. Encana also mitigates operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program.

In January 2016, the Alberta Government released the Modernized Royalty Framework ("MRF") outlining changes to the province's royalty structure. The MRF will result in the modernization and simplification of the royalty structure with changes to the royalty framework for crude oil, liquids and natural gas applying to new wells drilled after January 1, 2017 and existing royalties remaining in effect for 10 years on wells drilled (spud) before 2017. The Company is currently assessing the full impact of the changes to the royalty structure on its operations.

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 the public and 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 the Executive Leadership Team and the Board. The Corporate Responsibility, Environment, Health and Safety Committee of Encana's Board provides recommended environmental policies for approval by Encana's Board 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. Emergency response plans are in place to provide guidance during times of crisis. 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 continue to review 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.

In the state of Colorado, several cities 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 to date. Encana continues to work with state and local governments, academics and industry leaders to respond to hydraulic fracturing related concerns in Colorado. The Company recognizes that additional hydraulic fracturing ballot and/or local rule-making limiting or restricting oil and gas development activities are a possibility in the future and will continue to monitor and respond to these developments in 2016.

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.

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.

In Canada, the federal government and several provincial governments, including Alberta and British Columbia, have announced an enhanced focus on climate change policy in 2016. Encana continues to monitor developments, engage in consultations as appropriate and is actively managing the implementation of new climate-related policy and regulations in order to minimize the potential impact on its business.

On June 25, 2015, the Alberta Government announced that it was renewing and updating the Specified Gas Emitters Regulation (the “Regulation”), which governs carbon emissions and was set to expire on June 30, 2015. The Regulation requires any facility that emits 100,000 tonnes or more of greenhouse gases per year to reduce their emissions intensity. The renewed Regulation increases the reduction target from 12 percent to 20 percent by 2017 and increases the cost of carbon from C$15 per tonne to C$30 per tonne by 2017 for those facilities that are unable to meet the specified reduction targets. Encana does not own or operate any facilities which exceed the 100,000 tonne threshold and, as a result, is not currently subject to the Regulation.

In the U.S., the federal government has noted climate change action as a priority for the current administration and the Environmental Protection Agency (“EPA”) has outlined a series of steps to address methane and volatile organic compound emissions from the oil and gas industry, including a new goal to reduce oil and gas methane emissions by 40 to 45 percent from 2012 levels by 2025. The reductions will be achieved through proposed regulatory and voluntary measures. Encana continues to monitor these developments, provide comment as appropriate and assess the potential impact on its business.

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 deployment 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 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 GHG develop in the jurisdictions where Encana operates, inevitably price signals begin to emerge. 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 planning. Management and the Board review the impact of a variety of carbon constrained scenarios on its business plans, with a current price range from approximately $20 to $125 per tonne of emissions applied to a range of emissions coverage levels. 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.

Controls and Procedures

Disclosure Controls and Procedures

The Company's President and Chief Executive Officer ("CEO") and Executive Vice-President and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that:

- Material information relating to the Company is made known to the CEO and CFO by others; and
- Information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's disclosure controls and procedures at the financial year end of the Company. Based on their evaluation, the officers have concluded that Encana's disclosure controls and procedures were effective as at December 31, 2015.

Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting, which is a process designed by, or designed under the supervision of the CEO and CFO, and effected by the Board, Management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP.

Under their supervision and with the participation of Management, including the CEO and CFO, an evaluation of the effectiveness of the Company's internal control over financial reporting was conducted at December 31, 2015, based on the Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, Management has concluded that the Company's internal control over financial reporting was effectively designed and operating effectively as at that date.

Encana previously limited the scope and design and subsequent evaluation of internal controls over financial reporting to exclude the controls, policies and procedures of Athlon, acquired through a business combination on November 13, 2014. During the second quarter of 2015, the Company completed the evaluation and integration of the controls, policies and procedures of Athlon and no material weaknesses were noted during the integration. There have been no changes to the Company's internal control over financial reporting during the year ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, the effectiveness of the internal control over financial reporting.

Limitations of the Effectiveness of Controls

The Company's control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements. Control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation and should not be expected to prevent all errors or fraud. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, was appointed by a vote of shareholders at the Company's last annual meeting to audit and provide independent opinions on both the Consolidated Financial Statements and the Company's internal control over financial reporting as at December 31, 2015, as stated in their Auditor's Report which is included in our audited Consolidated Financial Statements for the year ended December 31, 2015.

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, 2015. 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, gain or loss 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 2015, Encana recorded ceiling test impairments, which are discussed further in the Results of Operations section of this MD&A.

Annually, all of Encana's natural gas, oil and NGL reserves and resources are evaluated and reported on by IQREs. 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 natural gas and oil properties or the future net cash flows expected to be generated from such properties. The discounted after-tax future net cash flows do not consider the fair market value of unamortized unproved properties, or probable or possible natural gas and liquids reserves. In addition, there is no consideration given to the effect of future changes in commodity prices. Encana manages its business using estimates of reserves and resources based on forecast prices and costs.

Business Combinations

Encana follows the acquisition method of accounting for business combinations. Assets acquired and liabilities assumed are recognized at the date of acquisition at their respective estimated fair values. Any excess of the purchase price over the estimated fair values of the net assets acquired is recorded as goodwill. Any deficiency of the purchase price over the estimated fair values of the net assets acquired is recorded as a gain in net earnings. In determining fair value, Encana utilized valuation methodologies including the income approach.

The assumptions made in performing these valuations include discount rates, future commodity prices and costs, the timing of development activities, projections of oil and gas reserves, estimates to abandon and reclaim producing wells and tax amortization benefits available to a market participant. Any significant change in key assumptions may cause the acquisition accounting to be revised, including the recognition of additional goodwill or discount on acquisition.

The valuation of fair values are determined based on information that existed at the time of the acquisition, utilizing expectations and assumptions that would be available to and made by a market participant. However,

there is no assurance the underlying assumptions or estimates associated with the valuation will occur as initially expected. Changes in key assumptions and estimates can impact net earnings through ceiling test impairments, impairments of goodwill, or lower future operating results.

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, 2015 and has determined that no write-down is required.

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.

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 other derivative contracts related to certain payment obligations are recognized in revenues as the obligations 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

On January 1, 2015, Encana adopted Accounting Standard Update ("ASU") 2014-08, *Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* as issued by the Financial Accounting Standards Board ("FASB"). The update amends the criteria and expands the disclosures for reporting discontinued operations. Under the new criteria, only disposals representing a strategic shift in operations would qualify as a discontinued operation. The amendments have been applied prospectively and have not had a material impact on the Company's Consolidated Financial Statements.

On December 31, 2015, Encana early adopted ASU 2015-17, *Balance Sheet Classification of Deferred Taxes*, which requires deferred income tax assets and liabilities to be classified as non-current on the balance sheet. Previously, deferred income tax assets and liabilities were classified as current and non-current on the balance sheet. The amendments have been applied retrospectively and had no impact on the Company's results of operations or cash flows. The impacts on the Company's Consolidated Balance Sheet are as follows:

As at December 31 ($ millions)	**2015**	2014	2013
Prior to Adoption of ASU 2015-17:			
Deferred Income Taxes			
Current Assets	**$ 22**	$ -	$ 118
Non-current Assets	**1,060**	296	939
Current Liabilities	**1**	128	3
Non-current Liabilities	**24**	1,829	-
Adoption of ASU 2015-17:			
Deferred Income Taxes			
Non-current Assets	**$ 1,081**	$ 206	$ 1,054
Non-current Liabilities	**24**	1,867	-

New Standards Issued Not Yet Adopted

As of January 1, 2016, Encana will be required to adopt the following pronouncements issued by the FASB:

- ASU 2014-12, *Compensation – Stock Compensation: Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved After the Requisite Service Period*. The update requires that a performance target that affects vesting and could be achieved after the requisite service period be treated as a performance condition. The amendments will be applied prospectively and are not expected to have a material impact on the Company's Consolidated Financial Statements.
- ASU 2015-02, *Amendments to the Consolidation Analysis*. The update requires limited partnerships and similar entities to be evaluated under the variable interest and voting interest models, eliminate the presumption that a general partner should consolidate a limited partnership, and simplify the identification of variable interests and related effect on the primary beneficiary criterion when fees are paid to a decision maker. The amendments can be applied using either a full retrospective approach or a modified retrospective approach at the date of adoption. The amendments are not expected to have a material impact on the Company's Consolidated Financial Statements.

- ASU 2015-03, *Simplifying the Presentation of Debt Issuance Costs*. The update requires debt issuance costs to be presented on the balance sheet as a deduction from the carrying amount of the related liability. Currently, debt issuance costs are presented as a deferred charge within assets. In August 2015, the FASB issued ASU 2015-15, *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* The update further clarifies that regardless of whether there are outstanding borrowings, debt issuance costs arising from credit arrangements can be presented as an asset and subsequently amortized ratably over the term of the arrangement. These amendments will be applied retrospectively. As at December 31, 2015, $30 million of debt issuance costs were presented in Other Assets on the Company's Consolidated Balance Sheet ($39 million as at December 31, 2014).

As of January 1, 2018, Encana will be required to adopt ASU 2014-09, *Revenue from Contracts with Customers* under Topic 606, which was the result of a joint project by the FASB and International Accounting Standards Board. The new standard replaces Topic 605, *Revenue Recognition*, and other industry-specific guidance in the Accounting Standards Codification. The new standard is based on the principle that revenue is recognized on the transfer of promised goods or services to customers in an amount that reflects the consideration the company expects to be entitled to in exchange for those goods or services. In August 2015, the FASB issued ASU 2015-14, *Deferral of Effective Date for Revenue from Contracts with Customers*, which deferred the effective date of ASU 2014-09, but permits early adoption using the original effective date of January 1, 2017. The standard can be applied using one of two retrospective application methods at the date of adoption. Encana is currently assessing the potential impact of the standard on the Company's Consolidated Financial Statements.

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; Free Cash Flow; Operating Earnings (Loss); Upstream Operating Cash Flow, excluding Hedging; Operating Netback; Debt to Debt Adjusted Cash Flow; and Debt to Adjusted Capitalization. Management's use of these measures is discussed further below.

Cash Flow and Free 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.

Free Cash Flow is a non-GAAP measure defined as Cash Flow in excess of capital investment, excluding net acquisitions and divestitures, and is used to determine the funds available for other investing and/or financing activities.

	2015					2014					2013
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Cash From (Used in) Operating Activities	**$ 1,681**	**$ 448**	**$ 453**	**$ 298**	**$ 482**	$ 2,667	$ 261	$ 696	$ 767	$ 943	$ 2,289
(Add back) deduct:											
Net change in other assets and liabilities	**(11)**	**7**	**(18)**	**7**	**(7)**	(43)	(15)	(11)	(8)	(9)	(80)
Net change in non-cash working capital	**262**	**58**	**100**	**110**	**(6)**	(9)	(141)	155	119	(142)	(179)
Cash tax on sale of assets	**-**	**-**	**-**	**-**	**-**	(215)	40	(255)	-	-	(33)
Cash Flow	**$ 1,430**	**$ 383**	**$ 371**	**$ 181**	**$ 495**	$ 2,934	$ 377	$ 807	$ 656	$ 1,094	$ 2,581
Deduct:											
Capital investment	**2,232**	**280**	**473**	**743**	**736**	2,526	857	598	560	511	2,712
Free Cash Flow	**$ (802)**	**$ 103**	**$ (102)**	**$ (562)**	**$ (241)**	$ 408	$ (480)	$ 209	$ 96	$ 583	$ (131)

Operating Earnings

Operating Earnings (Loss) is a non-GAAP measure that adjusts Net Earnings (Loss) Attributable to Common Shareholders by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. Operating Earnings (Loss) 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 (Loss) is defined as Net Earnings (Loss) Attributable to Common Shareholders 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, non-operating foreign exchange gains/losses, gains/losses on divestitures, income taxes related to divestitures and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

	2015					2014					2013
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Net Earnings (Loss) Attributable to Common Shareholders	**$ (5,165)**	**$ (612)**	**$ (1,236)**	**$ (1,610)**	**$ (1,707)**	$3,392	$ 198	$2,807	$ 271	$ 116	$ 236
After-tax (addition) / deduction:											
Unrealized hedging gain (loss)	**(244)**	**(66)**	**107**	**(187)**	**(98)**	306	341	160	8	(203)	(232)
Impairments	**(4,130)**	**(514)**	**(1,066)**	**(1,328)**	**(1,222)**	-	-	-	-	-	(16)
Restructuring charges [1]	**(45)**	**(5)**	**(20)**	**(10)**	**(10)**	(24)	(4)	(5)	(5)	(10)	(64)
Non-operating foreign exchange gain (loss)	**(702)**	**(96)**	**(212)**	**114**	**(508)**	(407)	(151)	(218)	156	(194)	(282)
Gain (loss) on divestitures	**9**	**-**	**(2)**	**1**	**10**	2,523	(11)	2,399	135	-	-
Income tax adjustments	**8**	**(42)**	**(19)**	**(33)**	**102**	(8)	(12)	190	(194)	8	28
Operating Earnings (Loss) [1]	**$ (61)**	**$ 111**	**$ (24)**	**$ (167)**	**$ 19**	$1,002	$ 35	$ 281	$ 171	$ 515	$ 802

(1) In continued support of Encana's strategy, organizational structure changes were formalized in Q2 2015 and resulted in a revision to the Q1 2015 Operating Earnings to exclude restructuring charges incurred in the first quarter.

Upstream Operating Cash Flow, excluding Hedging

Upstream Operating Cash Flow, excluding Hedging is a non-GAAP measure that adjusts the Canadian and USA Operations revenues, net of royalties for production, mineral and other taxes, transportation and processing expense, operating expense and the impacts of realized hedging. Management monitors Upstream Operating Cash Flow, excluding Hedging as it reflects operating performance and measures the Company's portfolio transition to higher margin production. Upstream Operating Cash Flow, excluding Hedging is reconciled to GAAP measures in the Results of Operations section of this MD&A. The table below totals Upstream Operating Cash Flow for Encana.

	2015					2014					2013
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Upstream Operating Cash Flow											
Canadian Operations	**$ 988**	**$ 204**	**$ 200**	**$ 171**	**$ 413**	$2,146	$ 341	$ 477	$ 447	$ 881	$1,681
USA Operations	**1,276**	**348**	**331**	**308**	**289**	1,772	480	505	353	434	1,511
	$2,264	**$ 552**	**$ 531**	**$ 479**	**$ 702**	$3,918	$ 821	$ 982	$ 800	$1,315	$3,192
(Add back) deduct:											
Realized Hedging Gain (Loss)											
Canadian Operations	**$ 495**	**$ 129**	**$ 109**	**$ 101**	**$ 156**	$ (56)	$ 49	$ 19	$ (49)	$ (75)	$ 276
USA Operations	**425**	**162**	**108**	**63**	**92**	(25)	78	11	(49)	(65)	264
	$ 920	**$ 291**	**$ 217**	**$ 164**	**$ 248**	$ (81)	$ 127	$ 30	$ (98)	$ (140)	$ 540
Upstream Operating Cash Flow, excluding Hedging											
Canadian Operations	**$ 493**	**$ 75**	**$ 91**	**$ 70**	**$ 257**	$2,202	$ 292	$ 458	$ 496	$ 956	$1,405
USA Operations	**851**	**186**	**223**	**245**	**197**	1,797	402	494	402	499	1,247
	$1,344	**$ 261**	**$ 314**	**$ 315**	**$ 454**	$3,999	$ 694	$ 952	$ 898	$1,455	$2,652

Operating Netback

Operating Netback is a common metric used in the oil and gas industry to measure operating performance by product. Operating Netbacks are calculated by determining product revenues, net of royalties and deducting costs associated with delivering the product to market, including production, mineral and other taxes, transportation and processing expense and operating expense. The Operating Netback calculation is shown in the Results of Operations section of this MD&A.

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)		**2015**		2014		2013
Debt	**$**	**5,363**	$	7,340	$	7,124
Cash Flow		**1,430**		2,934		2,581
Interest Expense, after tax		**452**		486		421
Debt Adjusted Cash Flow	**$**	**1,882**	$	3,420	$	3,002
Debt to Debt Adjusted Cash Flow		**2.8x**		2.1x		2.4x

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, total 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)		**2015**		2014		2013
Debt	**$**	**5,363**	$	7,340	$	7,124
Total Shareholders' Equity		**6,167**		9,685		5,147
Equity Adjustment for Impairments at December 31, 2011		**7,746**		7,746		7,746
Adjusted Capitalization	**$**	**19,276**	$	24,771	$	20,017
Debt to Adjusted Capitalization		**28%**		30%		36%

Advisory

Forward-Looking Statements

This document contains certain forward-looking statements or information (collectively, "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements include:

- anticipated Cash Flow
- anticipated cash and cash equivalents
- expected proceeds from announced divestitures, use of proceeds therefrom, satisfaction of closing conditions and timing of closing
- anticipated hedging and outcomes of risk management program
- the projections and expectation of meeting the targets contained in the Company's 2016 corporate guidance
- growth in long-term shareholder value
- anticipated oil, natural gas and NGLs prices
- expected future interest expense savings
- anticipated future cost and operating efficiencies
- the Company's expectation to fund its 2016 commitments and obligations from Cash Flow and cash and cash equivalents
- managing risk, including the impact of changes to the royalty structure
- flexibility of capital spending plans
- estimates of reserves and resources
- expected production and product type
- anticipated revenues and operating expenses
- expansion of future midstream services
- level of expenditures and impact of environmental legislation and changes in laws or regulations
- financial flexibility and discipline, access to cash and cash equivalents and other methods of funding, the ability to meet financial obligations, manage debt and financial ratios, finance growth and compliance with financial covenants
- impact to Encana as a result of a downgrade to its credit rating
- access to the Company's credit facility
- planned annualized 2016 dividend and the declaration and payment of future dividends, if any
- potential future discounts, if any, in connection with the DRIP
- statements with respect to future ceiling test impairments
- the continued evolution of the Company's resource play hub model to drive greater productivity and cost efficiencies
- statements with respect to its strategic objectives
- the adequacy of the Company's provision for taxes and legal claims
- anticipated proceeds and future benefits from various joint venture, partnership and other agreements
- the possible impact and timing of accounting pronouncements, rule changes and standards

Readers are cautioned against unduly relying on forward-looking statements which, by their nature, involve numerous assumptions, risks and uncertainties that may cause such statements not to occur, or results to differ materially from those expressed or implied. These assumptions include:

- achieving average production for 2016 of between 1.30 Bcf/d and 1.40 Bcf/d of natural gas and 120 Mbbls/d to 130 Mbbls/d of liquids
- availability of attractive hedges and enforceability of risk management program
- effectiveness of the Company's resource play hub model to drive productivity and efficiencies
- results from innovations
- the expectation that counterparties will fulfill their obligations under the gathering, midstream and marketing agreements
- access to transportation and processing facilities where Encana operates
- the ability to satisfy certain closing conditions, the successful closing of, and the value of post-closing and other adjustments associated with announced divestitures
- expectations and projections made in light of, and generally consistent with, Encana's historical experience and its perception of historical trends, including with respect to the pace of technological development, the benefits achieved and general industry expectations

Risks and uncertainties that may affect these business outcomes include: the ability to generate sufficient Cash Flow to meet the Company's obligations; risks inherent to closing announced divestitures on a timely basis or at all and adjustments that may reduce the expected proceeds and value to Encana; commodity price volatility; ability to secure adequate product transportation and potential pipeline curtailments; variability and discretion of Encana's Board to declare and pay dividends, if any; the timing and costs of well, facilities and pipeline construction; business interruption and casualty losses or unexpected technical difficulties; counterparty and credit risk; risk and effect of a downgrade in credit rating, including below an investment-grade credit rating, and its impact on access to capital markets and other sources of liquidity; fluctuations in currency and interest rates; assumptions based upon the Company's 2016 corporate guidance; failure to achieve anticipated results from cost and efficiency initiatives; risks inherent in marketing operations; risks associated with technology; changes in or interpretation of royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations; the Company's ability to acquire or find additional reserves; 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; risks associated with past and future 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; and other risks and uncertainties impacting Encana's business as described from time to time in its most recent MD&A, financial statements, AIF and Form 40-F, as filed on SEDAR and EDGAR.

Although Encana believes 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 assumptions, risks and uncertainties referenced above are not exhaustive. Forward-looking statements are made as of the date of this document and, except as required by law, Encana undertakes no obligation to update publicly or revise any forward-looking statements. The forward-looking statements contained in this document are expressly qualified by these cautionary statements.

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 24, 2016, 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

NI 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. In addition, certain disclosures have been prepared in accordance with U.S. disclosure requirements. The Company’s U.S. protocol disclosure is included in Note 27 (unaudited) to the Company’s Consolidated Financial Statements for the year ended December 31, 2015 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

The conversion of natural gas volumes to BOE is on the basis of six thousand cubic feet to one barrel. BOE is based on a generic energy equivalency conversion method primarily applicable at the burner tip and does not represent economic value equivalency at the wellhead. Readers are cautioned that BOE may be misleading, particularly if used in isolation.

Play and Resource Play

Play is a term used by Encana which encompasses resource plays, geological formations and conventional plays. 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.

Additional Information

Further information regarding Encana Corporation, including its AIF, 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.