Encana Corporation

Management's Discussion and Analysis
(Prepared using U.S. GAAP)

For the year ended December 31, 2011

(Prepared in U.S. Dollars)

April 24, 2012

United States Generally Accepted Accounting Principles
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 United States ("U.S.") generally accepted accounting principles ("U.S. GAAP") Consolidated Financial Statements for the year ended December 31, 2011.

The U.S. GAAP Consolidated Financial Statements and comparative information have been prepared in accordance with U.S. GAAP and in U.S. dollars, except where another currency has been indicated. Production volumes are presented on an after royalties basis consistent with U.S. oil and gas reporting and the disclosure of U.S. oil and gas companies. The term "liquids" is used to represent oil, natural gas liquids ("NGLs") and condensate. The term "liquids-rich" is used to represent natural gas streams with associated liquids volumes. This document is dated April 24, 2012.

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

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

Encana's Strategic Objectives

Encana is a leading North American energy producer that is focused on growing its strong portfolio of diverse resource plays producing natural gas, oil and NGLs. Encana is pursuing the key business objectives of maintaining financial strength, optimizing capital investments in the Company's highest return projects and continuing to pay a stable dividend to shareholders as it pursues disciplined, responsible and reliable low-cost production growth.

Encana's extensive portfolio of reserves and economic contingent resources in high-growth resource plays in major North American basins serves as the foundation for the Company's long-term strategy of accelerating the value recognition of its assets. Encana has a history of entering prospective basins early and leveraging technology to unlock resources and build the underlying productive capacity at a low cost.

Encana continually strives to improve operating efficiencies, foster technological innovation and lower its cost structures, while reducing its environmental footprint through resource play optimization. The Company's resource play hub model, which utilizes highly integrated production facilities, is used to develop resources by drilling multiple wells from central pad sites. Repeatable operations lend themselves to ongoing cost reductions through optimization of equipment and processes by applying continuous improvement techniques.

Encana is focused on balancing capital investment to build long-term production growth capacity with near term market uncertainty. Encana's approach for 2012 is to align capital investment plus anticipated dividends with expected cash flow generation, before divestiture proceeds. Proceeds from planned divestitures and joint venture transactions are expected to provide additional financial flexibility. Given the current natural gas pricing environment, the Company expects that many of its drier natural gas plays will see a reduced capital program, while a growing portion of capital investment will be directed towards oil and liquids-rich development and exploration opportunities. Encana continues to focus on attracting third-party investments to advance development of the Company's reserves and resources.

At December 31, 2011, Encana had hedged approximately 1,955 million cubic feet ("MMcf") per day ("MMcf/d") of expected 2012 natural gas production using NYMEX fixed price contracts at an average price of $5.80 per thousand cubic feet ("Mcf"). In addition, Encana had hedged approximately 505 MMcf/d of expected 2013 natural gas production at an average price of $5.24 per Mcf. The Company's Cash Flow and netbacks will benefit from the hedging program during periods of lower prices.

Encana is working to expand the use of natural gas in North America in power generation, transportation and industrial applications. Accessing new natural gas markets, including the export of liquefied natural gas ("LNG"), is also part of this initiative. During 2011, Encana acquired a 30 percent interest in the planned Kitimat LNG export terminal in British Columbia.

Further information on expected 2012 results can be found in Encana's 2012 Corporate Guidance on the Company's website www.encana.com.

Encana's Business

Encana's reportable segments are as follows:

- **Canada** includes the Company's exploration for, development of, and production of natural gas and liquids and other related activities within the Canadian cost centre.

- **USA** includes the Company's exploration for, development of, and production of natural gas and liquids and other related activities within the U.S. cost centre.

- **Market Optimization** is primarily responsible for the sale of the Company's proprietary production. These results are included in the Canada and USA segments. Market optimization activities include third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. These activities are reflected in the Market Optimization segment.

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

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.

Encana's operations are currently organized into two upstream operating divisions as follows:

- **Canadian Division** includes the exploration for, development of, and production of natural gas, oil, NGLs and other related activities within Canada. Four key resource plays are located in the Division: (i) Greater Sierra in northeast British Columbia, including Horn River; (ii) Cutbank Ridge in Alberta and British Columbia, including Montney; (iii) Bighorn in west central Alberta; and (iv) Coalbed Methane ("CBM") in southern Alberta. The Canadian Division also includes the Deep Panuke natural gas project offshore Nova Scotia.

- **USA Division** includes the exploration for, development of, and production of natural gas, oil, NGLs and other related activities within the U.S. Four key resource plays are located in the Division: (i) Jonah in southwest Wyoming; (ii) Piceance in northwest Colorado; (iii) Haynesville in Louisiana; and (iv) Texas, including East Texas and North Texas.

On November 30, 2009, Encana completed a corporate reorganization (the "Split Transaction") to split into two independent publicly traded energy companies – Encana and Cenovus Energy Inc. ("Cenovus"). The Company's comparative results prior to November 30, 2009 include the results of operations from assets transferred to Cenovus. The results from former Canadian upstream assets transferred to Cenovus are presented as Canada – Other within continuing operations in accordance with U.S. GAAP full cost accounting. The former U.S. downstream refining operations are reported as discontinued operations. Further details can be found in Notes 2 and 3 to the U.S. GAAP Consolidated Financial Statements.

Results Overview

Highlights

In the year ended December 31, 2011, Encana reported:

- Cash Flow of $4,216 million, Operating Earnings of $1,191 million and Net Earnings of $5 million.
- Average natural gas production volumes of 3,333 MMcf/d, which increased from 3,184 MMcf/d in 2010.
- Average oil and NGL production volumes of 24.0 thousand barrels (“Mbbls”) per day (“Mbbls/d”), which increased from 22.8 Mbbls/d in 2010.
- Realized financial natural gas and other commodity hedging gains of $638 million after tax.
- Average natural gas prices, including financial hedges, of $4.96 per Mcf. Average liquids prices of $85.36 per barrel (“bbl”).
- Dividends paid of $0.80 per share.

Significant developments for the Company during the year ended December 31, 2011 included the following:

- Completed planned divestitures for total proceeds of $891 million of Encana’s interest in the Cabin natural gas processing plant in British Columbia, the Fort Lupton natural gas processing plant in Colorado and the South Piceance natural gas gathering assets in Colorado.
- Closed the majority of the sale of its North Texas natural gas producing assets for proceeds of $836 million. In the first quarter of 2012, Encana closed the remainder of the sale and received proceeds of $114 million.
- Agreed to sell two natural gas processing plants in the Cutbank Ridge area of British Columbia and Alberta for approximately C$920 million. The sale closed on February 9, 2012 and the proceeds were received.
- Entered into negotiations with Mitsubishi Corporation (“Mitsubishi”) to jointly develop certain undeveloped lands owned by Encana. On February 17, 2012, Encana announced that the Company and Mitsubishi had entered into a partnership agreement for the development of Cutbank Ridge lands in British Columbia. Under the agreement, Mitsubishi will invest approximately C$2.9 billion for a 40 percent interest in the partnership. The transaction closed on February 24, 2012, and C$1.45 billion was received.
- Acquired land and property totaling $515 million, which primarily included acreage with oil and liquids-rich production potential.
- Entered into deep cut processing arrangements, which will allow the Company to extract additional NGL volumes from its natural gas streams in the Alberta Deep Basin starting in 2012.
- Acquired a 30 percent interest in the planned Kitimat LNG export terminal in British Columbia.
- Entered into an agreement to be the sole LNG fueling supplier to a fleet of 200 LNG heavy-duty trucks in Louisiana through its mobile and permanent LNG fueling stations and opened four compressed natural gas fueling stations.
- Completed a public offering of senior unsecured notes in the U.S. in two series totaling $1.0 billion. Encana also renewed committed revolving bank credit facilities in Canada and the U.S. totaling $4.9 billion, which mature in October 2015.

Financial Results

($ millions, except per share amounts)	2011 Annual	2011 Q4	2011 Q3	2011 Q2	2011 Q1	2010 Annual	2010 Q4	2010 Q3	2010 Q2	2010 Q1	2009 Annual
Cash Flow [1, 2]	**$ 4,216**	**$ 983**	**$ 1,181**	**$ 1,089**	**$ 963**	$ 4,439	$ 917	$ 1,132	$ 1,217	$ 1,173	$ 6,762
per share – diluted	**5.72**	**1.33**	**1.60**	**1.48**	**1.31**	6.00	1.25	1.54	1.65	1.57	9.00
Operating Earnings [1, 2]	**1,191**	**232**	**389**	**352**	**218**	1,474	242	330	427	475	3,593
per share – diluted	**1.62**	**0.31**	**0.53**	**0.48**	**0.30**	1.99	0.33	0.45	0.58	0.63	4.78
Net Earnings from Continuing Operations [2]	**5**	**(476)**	**459**	**383**	**(361)**	2,343	131	763	(132)	1,581	(5,554)
per share – basic	**0.01**	**(0.65)**	**0.62**	**0.52**	**(0.49)**	3.17	0.18	1.04	(0.18)	2.11	(7.40)
per share – diluted	**0.01**	**(0.65)**	**0.62**	**0.52**	**(0.49)**	3.17	0.18	1.04	(0.18)	2.11	(7.40)
Net Earnings [2, 3]	**5**	**(476)**	**459**	**383**	**(361)**	2,343	131	763	(132)	1,581	(5,524)
per share – basic	**0.01**	**(0.65)**	**0.62**	**0.52**	**(0.49)**	3.17	0.18	1.04	(0.18)	2.11	(7.36)
per share – diluted	**0.01**	**(0.65)**	**0.62**	**0.52**	**(0.49)**	3.17	0.18	1.04	(0.18)	2.11	(7.36)
Revenues, Net of Royalties [2]	**8,467**	**2,461**	**2,353**	**1,986**	**1,667**	8,870	1,431	2,425	1,469	3,545	11,282
Total Assets	**23,415**					23,007					21,426
Total Debt	**8,150**					7,682					7,824
Cash & Cash Equivalents	**800**					699					4,381

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

(2) 2009 includes the results from the upstream assets transferred to Cenovus, which were reported as continuing operations in accordance with U.S. GAAP full cost accounting.

(3) 2009 Net Earnings includes the results from the U.S. downstream refining assets transferred to Cenovus, which were reported as discontinued operations.

Q4 2011 versus Q4 2010

Cash Flow of $983 million increased $66 million primarily due to higher production volumes, higher liquids prices and higher realized financial hedging gains, partially offset by lower natural gas prices. In the three months ended December 31, 2011:

- Average natural gas production volumes increased 229 MMcf/d to 3,459 MMcf/d from 3,230 MMcf/d in 2010. Average oil and NGL production volumes increased 3.4 Mbbls/d to 23.9 Mbbls/d in 2011 from 20.5 Mbbls/d in 2010.
- Average natural gas prices, excluding financial hedges, were $3.73 per Mcf compared to $3.93 per Mcf in 2010. Average liquids prices, excluding financial hedges, were $85.44 per bbl in 2011 compared to $71.05 per bbl in 2010.
- Realized financial hedging gains were $223 million after tax compared to gains of $209 million after tax in 2010.

Operating Earnings of $232 million decreased $10 million primarily due to lower natural gas prices and higher depreciation, depletion and amortization ("DD&A"). These were partially offset by higher production volumes, higher liquids prices and higher realized financial hedging gains.

Net Earnings, a loss of $476 million, decreased $607 million primarily due to an after-tax non-cash ceiling test impairment of $1,105 million (2010 – nil), partially offset by higher after-tax combined realized and unrealized financial hedging gains of $620 million (2010 – $60 million gain reversal). The Company's non-cash ceiling test impairment primarily resulted from the decline in the 12-month average trailing natural gas prices. Ceiling test impairments are recognized when the capitalized costs aggregated at the country cost centre level exceed the sum of the estimated after-tax future net cash flows from proved reserves, using the 12-month average trailing prices and unescalated future development and production costs, discounted at 10 percent, plus unproved property costs, as prescribed by U.S. GAAP full cost accounting. Net earnings also decreased due to the items discussed in operating earnings.

2011 versus 2010

Cash Flow of $4,216 million decreased $223 million primarily due to lower natural gas prices, lower realized financial hedging gains and higher transportation expense. These were partially offset by higher production volumes and higher liquids prices. In 2011:

- Average natural gas production volumes increased 149 MMcf/d to 3,333 MMcf/d from 3,184 MMcf/d in 2010. Average oil and NGL production volumes increased 1.2 Mbbls/d to 24.0 Mbbls/d in 2011 from 22.8 Mbbls/d in 2010.
- Average natural gas prices, excluding financial hedges, were $4.17 per Mcf compared to $4.47 per Mcf in 2010. Average liquids prices, excluding financial hedges, were $85.36 per bbl in 2011 compared to $66.72 per bbl in 2010.
- Realized financial hedging gains were $638 million after tax compared to gains of $808 million after tax in 2010.

Operating Earnings of $1,191 million decreased $283 million primarily due to lower natural gas prices, lower realized financial hedging gains, higher transportation expense and higher DD&A. These were partially offset by higher production volumes, higher liquids prices and lower deferred tax expense.

Net Earnings of $5 million decreased $2,338 million primarily due to after-tax non-cash ceiling test impairments of $1,687 million (2010 – nil), lower combined realized and unrealized financial hedging gains of $1,238 million (2010 – $1,442 million), and a non-operating foreign exchange loss of $99 million (2010 – $235 million gain). The non-cash ceiling test impairments primarily resulted from the decline in the 12-month average trailing natural gas prices. Net earnings also decreased due to the items discussed in operating earnings.

Encana’s quarterly net earnings are impacted by fluctuations in commodity prices and foreign exchange rates, which can be found below. In addition, combined realized and unrealized hedging gains after tax contributed to the quarterly volatility in 2011 net earnings as follows: Q1 – $50 million; Q2 – $149 million; Q3 – $419 million; and Q4 – $620 million. In 2010, the after-tax gains were as follows: Q1 – $1,037 million; Q2 – $77 million gain reversal; Q3 – $542 million; and Q4 – $60 million gain reversal.

2010 versus 2009

Cash Flow of $4,439 million decreased $2,323 million primarily due to lower realized financial hedging gains and the inclusion of the Cenovus results in the 2009 comparative. These were partially offset by higher commodity prices, higher natural gas production volumes for the Canadian and USA Divisions and a current income tax recovery. In 2010:

- Average natural gas production volumes increased 344 MMcf/d to 3,184 MMcf/d from 2,840 MMcf/d in 2009 for the Canadian and USA Divisions. The 2009 natural gas production totaled 3,602 MMcf/d, which included 762 MMcf/d of Cenovus volumes. Average oil and NGL production volumes decreased slightly to 22.8 Mbbls/d in 2010 for the Canadian and USA Divisions. The 2009 oil and NGL production totaled 127.1 Mbbls/d, which included 99.9 Mbbls/d of Cenovus volumes.
- Average natural gas prices, excluding financial hedges, were $4.47 per Mcf in 2010 compared to $3.73 per Mcf in 2009 for the Canadian and USA Divisions. The 2009 average natural gas price, including Cenovus operations, was $3.69 per Mcf. Average liquids prices, excluding financial hedges, were $66.72 per bbl in 2010 compared to $48.15 per bbl in 2009 for the Canadian and USA Divisions. The 2009 average liquids price, including Cenovus operations, was $49.65 per bbl.
- Realized financial hedging gains were $808 million after tax compared to gains of $2,250 million after tax in 2009 for the Canadian and USA Divisions. The 2009 realized financial hedging gains totaled $2,935 million, which included $685 million related to Cenovus operations.

Operating Earnings of $1,474 million decreased $2,119 million primarily due to lower realized financial hedging gains, higher deferred tax expense and the inclusion of the Cenovus results in the 2009 comparative. These were partially offset by higher commodity prices, higher natural gas production volumes for the Canadian and USA Divisions, a current income tax recovery and lower DD&A related to the Canadian and USA Divisions.

Net Earnings of $2,343 million increased $7,867 million primarily due to an increase in after-tax unrealized hedging gains of $2,426 million and the inclusion of after-tax non-cash ceiling test impairments of $7,612 million in the 2009 comparative. The increase in net earnings was partially offset by the decrease due to the items discussed in operating earnings.

Quarterly Prices and Foreign Exchange Rates

	2011					2010					2009
(average for the period)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Encana Realized Pricing											
Natural Gas *($/Mcf)*											
Including hedging	**$ 4.96**	**$ 4.79**	**$ 5.01**	**$ 5.09**	**$ 5.00**	$ 5.48	$ 5.03	$ 5.27	$ 5.50	$ 6.14	$ 7.02
Excluding hedging	**4.17**	**3.73**	**4.32**	**4.42**	**4.26**	4.47	3.93	4.19	4.23	5.56	3.69
Liquids *($/bbl)*											
Including hedging	**85.36**	**85.44**	**82.43**	**92.66**	**80.70**	66.12	68.91	61.79	67.05	67.07	50.48
Excluding hedging	**85.36**	**85.44**	**82.43**	**92.66**	**80.70**	66.72	71.05	62.15	66.73	67.48	49.65
Natural Gas Price Benchmarks											
NYMEX *($/MMBtu)*	**4.04**	**3.55**	**4.20**	**4.31**	**4.11**	4.39	3.80	4.39	4.09	5.30	3.99
AECO *(C$/Mcf)*	**3.67**	**3.47**	**3.72**	**3.74**	**3.77**	4.13	3.58	3.72	3.86	5.36	4.14
Rockies (Opal) *($/MMBtu)*	**3.80**	**3.47**	**3.90**	**3.98**	**3.84**	3.94	3.44	3.53	3.66	5.14	3.09
HSC *($/MMBtu)*	**4.02**	**3.49**	**4.23**	**4.29**	**4.06**	4.38	3.78	4.33	4.04	5.36	3.78
Basis Differential *($/MMBtu)*											
AECO/NYMEX	**0.31**	**0.17**	**0.34**	**0.42**	**0.29**	0.40	0.28	0.83	0.32	0.19	0.40
Rockies/NYMEX	**0.24**	**0.08**	**0.30**	**0.33**	**0.27**	0.45	0.36	0.86	0.43	0.16	0.90
HSC/NYMEX	**0.02**	**0.06**	**(0.03)**	**0.02**	**0.05**	0.01	0.02	0.06	0.05	(0.06)	0.21
Oil Price Benchmark											
West Texas Intermediate (WTI) *($/bbl)*	**95.11**	**94.02**	**89.54**	**102.34**	**94.25**	79.55	85.18	76.28	77.99	78.88	62.09
Foreign Exchange											
U.S./Canadian Dollar Exchange Rate	**1.012**	**0.978**	**1.020**	**1.033**	**1.015**	0.971	0.987	0.962	0.973	0.961	0.876

Encana's financial results are influenced by fluctuations in commodity prices, price differentials and the U.S./Canadian dollar exchange rate. In 2011, Encana's average realized natural gas price, excluding hedging, reflected lower benchmark prices compared to 2010. Hedging activities contributed an additional $0.79 per Mcf to the average realized natural gas price in 2011. Encana's 2011 average realized liquids price, excluding hedging, reflected higher benchmark prices compared to 2010.

In 2010, Encana's average realized natural gas price, excluding hedging, reflected higher benchmark prices compared to 2009. Hedging activities contributed an additional $1.01 per Mcf to the 2010 average realized natural gas price and $3.33 per Mcf in 2009. Encana's 2010 average realized liquids price, excluding hedging, reflected higher benchmark prices compared to 2009.

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

At December 31, 2011, Encana had hedged approximately 1,955 MMcf/d of expected 2012 natural gas production using NYMEX fixed price contracts at an average price of $5.80 per Mcf. In addition, Encana had hedged approximately 505 MMcf/d of expected 2013 natural gas production at an average price of $5.24 per Mcf. The Company's hedging program helps sustain cash flow during periods of lower prices. For additional information see the Risk Management – Financial Risks section of this MD&A.

Reserves Quantities

Since its formation in 2002, Encana has retained independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of the Company's natural gas, oil and NGL reserves annually. The Company has a Reserves Committee of independent Board of Directors members, which 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 2011 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").

Supplementary oil and gas information, including proved reserves on an after royalties basis, is provided in accordance with U.S. disclosure requirements in Note 24 to the December 31, 2011 U.S. GAAP Consolidated Financial Statements. As Encana follows U.S. GAAP full cost accounting for natural gas, oil and NGL activities, the U.S. protocol reserves estimates are key inputs to the Company's depletion and ceiling test impairment calculations.

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

Canadian Protocol Reserves Quantities

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

(as at December 31)	Natural Gas *(Bcf)* 2011	2010	2009	Oil and NGLs *(MMbbls)* 2011	2010	2009
Canada	**7,067**	6,755	6,111	**106.5**	61.9	41.6
United States	**8,432**	9,299	8,172	**47.3**	47.4	55.7
Total	**15,499**	16,054	14,283	**153.8**	109.3	97.3

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

	Natural Gas *(Bcf)*			Oil and NGLs *(MMbbls)*			
	Canada	United States	Total	Canada	United States	Total	Total *(Bcfe)*
December 31, 2010	6,755	9,299	16,054	61.9	47.4	109.3	16,710
Extensions	808	886	1,694	48.9	1.8	50.7	1,999
Discoveries	10	1	11	0.8	1.9	2.7	27
Technical revisions	389	573	962	6.5	2.4	8.9	1,015
Economic factors	(234)	(182)	(416)	0.2	(0.1)	0.1	(416)
Acquisitions	82	28	110	0.3	-	0.3	112
Dispositions	(187)	(1,316)	(1,503)	(6.1)	(1.8)	(7.9)	(1,550)
Production	(556)	(857)	(1,413)	(6.0)	(4.3)	(10.3)	(1,475)
December 31, 2011	7,067	8,432	15,499	106.5	47.3	153.8	16,422

Encana's 2011 natural gas proved reserves before royalties of approximately 15.5 trillion cubic feet ("Tcf") decreased by 3.5 percent compared to 2010 primarily due to divestitures and economic factors. Additions of approximately 2.3 Tcf, before acquisitions and divestitures, replaced 159 percent of production before royalties during the year.

Encana's 2011 oil and NGL proved reserves before royalties of approximately 153.8 million barrels ("MMbbls") increased by 41 percent compared to 2010 primarily due to ongoing development and delineation activities. Additions of approximately 62.4 MMbbls, before acquisitions and divestitures, replaced 606 percent of production before royalties during the year.

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

	Natural Gas *(Bcf)*			Oil and NGLs *(MMbbls)*			
	Canada	United States	Total	Canada	United States	Total	Total *(Bcfe)*
December 31, 2010	6,298	7,477	13,775	54.8	38.5	93.3	14,335
Extensions and discoveries	849	1,303	2,152	17.7	5.6	23.3	2,292
Revisions (1)	84	(278)	(194)	31.8	(0.8)	31.0	(8)
Acquisitions	74	24	98	0.2	0.1	0.3	100
Dispositions	(167)	(1,007)	(1,174)	(4.8)	(1.3)	(6.1)	(1,211)
Production	(531)	(685)	(1,216)	(5.3)	(3.5)	(8.8)	(1,269)
December 31, 2011	6,607	6,834	13,441	94.4	38.6	133.0	14,239

(1) Includes economic factors.

Encana's 2011 natural gas proved reserves after royalties of approximately 13.4 Tcf decreased by 2.4 percent from 2010 due to divestitures and economic factors. Additions of approximately 2.0 Tcf, before acquisitions and divestitures, replaced 161 percent of production after royalties during the year.

Encana's 2011 oil and NGL proved reserves after royalties of approximately 133.0 MMbbls increased by 43 percent over 2010 due to ongoing development and delineation activities. Additions of approximately 54.3 MMbbls, before acquisitions and divestitures, replaced 617 percent of production after royalties during the year.

Forecast Prices

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

	Natural Gas		Liquids	
	Henry Hub *($/MMBtu)*	AECO *(C$/MMBtu)*	WTI *($/bbl)*	Edmonton [1] *(C$/bbl)*
2009 Price Assumptions				
2010	5.50	5.49	75.00	76.84
2011 - 2014	6.50	6.39 – 6.04	75.00	76.84
Thereafter	6.50	6.04	75.00	76.84
2010 Price Assumptions				
2011	4.73	4.35	79.53	81.93
2012 - 2015	5.33 – 6.01	4.94 – 5.78	82.65 – 86.68	85.88 – 91.61
Thereafter	6.18 – 6.63	5.97 – 6.48	83.72	88.37
2011 Price Assumptions				
2012	3.80	3.49	97.00	97.96
2013 - 2021	4.50 – 7.17	4.13 – 6.58	100.00 – 107.56	101.02 – 108.73
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr

(1) Light Sweet for 2011 and 2010; Mixed Sweet Blend for 2009.

U.S. Protocol Reserves Quantities

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

(as at December 31)	Natural Gas (Bcf) 2011	2010	2009	Oil and NGLs (MMbbls) 2011	2010	2009
Canada	**6,329**	6,117	5,349	**95.0**	54.3	35.5
United States	**6,511**	7,183	5,713	**38.2**	38.2	41.2
Total	**12,840**	13,300	11,062	**133.2**	92.5	76.7

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

	Natural Gas (Bcf) Canada	United States	Total	Oil and NGLs (MMbbls) Canada	United States	Total
December 31, 2010	6,117	7,183	13,300	54.3	38.2	92.5
Revisions and improved recovery	3	(204)	(201)	32.3	(0.7)	31.6
Extensions and discoveries	826	1,121	1,947	18.2	5.4	23.6
Purchase of reserves in place	72	23	95	0.2	0.1	0.3
Sale of reserves in place	(158)	(927)	(1,085)	(4.7)	(1.3)	(6.0)
Production	(531)	(685)	(1,216)	(5.3)	(3.5)	(8.8)
December 31, 2011	6,329	6,511	12,840	95.0	38.2	133.2

Encana's 2011 natural gas proved reserves after royalties of approximately 12.8 Tcf decreased by 3.5 percent compared to 2010 primarily due to divestitures and the impact of lower 12-month average trailing prices. Additions of approximately 1.7 Tcf, excluding the purchase and sale of lands with reserves attributable to them, replaced 144 percent of production after royalties during the year.

Encana's 2011 oil and NGL proved reserves after royalties of approximately 133.2 MMbbls increased by 44 percent compared to 2010 primarily due to activities in Canada. Additions of approximately 55.2 MMbbls, excluding the purchase and sale of lands with reserves attributable to them, replaced 627 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 price is calculated as the average of the prices on the first day of each month within the 12-month period.

	Natural Gas Henry Hub (\$/MMBtu)	AECO (C\$/MMBtu)	Liquids WTI (\$/bbl)	Edmonton [(1)] (C\$/bbl)
Reserves Pricing [(2)]				
2009	3.87	3.77	61.18	65.64
2010	4.38	4.03	79.43	76.22
2011	4.12	3.76	96.19	96.53

(1) Light Sweet for 2011 and 2010; Mixed Sweet Blend for 2009.

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

Production and Net Capital Investment

Production Volumes (After Royalties)

	2011					2010					2009
(average daily)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Natural Gas *(MMcf/d)*											
Canadian Division	**1,454**	**1,515**	**1,460**	**1,445**	**1,395**	1,323	1,395	1,390	1,327	1,177	1,224
USA Division	**1,879**	**1,944**	**1,905**	**1,864**	**1,801**	1,861	1,835	1,791	1,875	1,946	1,616
Canada – Other (1)	**-**	**-**	**-**	**-**	**-**	-	-	-	-	-	762
	3,333	**3,459**	**3,365**	**3,309**	**3,196**	3,184	3,230	3,181	3,202	3,123	3,602
Oil and NGLs *(Mbbls/d)*											
Canadian Division	**14.5**	**13.9**	**15.1**	**14.8**	**14.3**	13.2	11.3	14.3	13.5	13.6	15.9
USA Division	**9.5**	**10.0**	**9.3**	**9.5**	**9.0**	9.6	9.2	9.1	10.1	10.1	11.3
Canada – Other (1)	**-**	**-**	**-**	**-**	**-**	-	-	-	-	-	99.9
	24.0	**23.9**	**24.4**	**24.3**	**23.3**	22.8	20.5	23.4	23.6	23.7	127.1

(1) Represents former Canadian upstream operations transferred to Cenovus.

In 2011, average natural gas production volumes of 3,333 MMcf/d increased 149 MMcf/d from 2010 and average oil and NGL production volumes of 24.0 Mbbls/d increased 1.2 Mbbls/d from 2010. In the Canadian Division, higher volumes were primarily due to a successful drilling program in the key resource plays. In the USA Division, natural gas volumes were higher primarily due to a successful drilling program in Haynesville, partially offset by net divestitures and natural declines.

In 2010, average natural gas production volumes from the Canadian Division and USA Division increased 344 MMcf/d from 2009. In the Canadian Division, higher natural gas volumes were primarily due to a successful drilling program in the key resource plays, as well as bringing on shut-in and curtailed production, partially offset by net divestitures. In the USA Division, higher natural gas volumes were primarily due to a successful drilling program in the key resource plays, as well as bringing on shut-in and curtailed production, partially offset by net divestitures and natural declines. The 2009 average natural gas production volumes totaled 3,602 MMcf/d, which included 762 MMcf/d of Cenovus volumes.

In 2010, oil and NGL production volumes from the Canadian Division and USA Division decreased slightly to 22.8 Mbbls/d from 2009. The 2009 average oil and NGL production volumes totaled 127.1 Mbbls/d, which included 99.9 Mbbls/d of Cenovus volumes.

Net Capital Investment

($ millions)	**2011**	2010	2009
Canadian Division	**$ 2,031**	$ 2,214	$ 1,869
USA Division	**2,446**	2,502	1,821
Market Optimization	**2**	2	2
Corporate & Other	**131**	61	85
Canada – Other (1)	**-**	-	848
Capital Investment	**4,610**	4,779	4,625
Acquisitions	**515**	733	263
Divestitures	**(2,080)**	(883)	(1,178)
Net Acquisitions and Divestitures	**(1,565)**	(150)	(915)
Discontinued Operations (2)	**-**	-	829
Net Capital Investment	**$ 3,045**	$ 4,629	$ 4,539

(1) Represents former Canadian upstream operations transferred to Cenovus.

(2) Represents former U.S. downstream refining operations transferred to Cenovus.

2011 versus 2010

Capital investment during 2011 was primarily focused on continued development of Encana's North American key resource plays. Capital investment of $4,610 million was $169 million lower compared to 2010 primarily due to lower spending in Greater Sierra, Haynesville, Texas, Jonah and CBM, partially offset by increased spending in Piceance.

In 2011, the Company had acquisitions of $410 million in the Canadian Division and $105 million in the USA Division, which included land and property purchases that are complementary to existing Company assets. Land acquisitions were focused on acreage with oil and liquids-rich production potential.

Divestitures in 2011 were $350 million in the Canadian Division and $1,730 million in the USA Division. The Canadian Division divestitures included the sale of the Company's interest in the Cabin natural gas processing plant for proceeds of $48 million. The USA Division divestitures included the sales of the Fort Lupton natural gas processing plant for proceeds of $296 million, the South Piceance natural gas gathering assets for proceeds of $547 million and the majority of the North Texas natural gas producing assets for proceeds of approximately $836 million. Cash taxes increased by $114 million as a result of the sale of the South Piceance assets and the North Texas assets. Divestiture amounts are net of amounts recovered for capital expenditures incurred prior to the sale of certain natural gas gathering and processing assets. Divestitures in 2010 included the sale of non-core assets.

Encana is presently involved in a number of joint venture transactions with counterparties in both Canada and the U.S. These arrangements support the Company's long-term strategy of accelerating the value recognition of its assets. Sharing development costs with third parties enables Encana to advance project development while reducing capital investment, thereby improving project returns.

2010 versus 2009

Capital investment during 2010 was primarily focused on continued development of Encana's North American key resource plays. Capital investment for the Canadian and USA Divisions of $4,716 million in 2010 was $1,026 million higher compared to 2009 primarily due to higher spending in Haynesville and Greater Sierra and an increase in the average U.S./Canadian dollar exchange rate. Capital investment for 2009 also included $848 million attributable to Cenovus's upstream operations.

In 2010, the Company had acquisitions in the Canadian Division of $592 million (2009 – $190 million) and in the USA Division of $141 million (2009 – $46 million). These acquisitions included land and property purchases that are complementary to existing Company assets.

Divestitures of non-core assets in 2010 in the Canadian Division were $288 million (2009 – $1,000 million) and in the USA Division were $595 million (2009 – $73 million). The Canadian Division 2009 divestitures included the sale of mature conventional oil and natural gas assets.

Divisional Results

Canadian Division

Operating Cash Flow

	Operating Cash Flow ($ millions)			Natural Gas Netback ($/Mcf)			Oil & NGLs Netback ($/bbl)		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Revenues, Net of Royalties, excluding Hedging	**$ 2,507**	$ 2,350	$ 1,962	**$ 3.79**	$ 4.10	$ 3.71	**$ 85.41**	$ 64.79	$ 47.86
Realized Financial Hedging Gain	**365**	479	1,400	**0.69**	0.99	3.16	**-**	(1.04)	(0.02)
Expenses									
Production and mineral taxes	**15**	8	14	**0.02**	0.01	0.03	**0.90**	0.44	0.45
Transportation	**250**	197	154	**0.46**	0.40	0.33	**0.93**	0.82	1.06
Operating	**620**	563	522	**1.12**	1.09	1.10	**1.75**	3.24	3.62
Operating Cash Flow/Netback	**$ 1,987**	$ 2,061	$ 2,672	**$ 2.88**	$ 3.59	$ 5.41	**$ 81.83**	$ 59.25	$ 42.71

	Natural Gas (MMcf/d)			Oil & NGLs (Mbbls/d)		
	2011	2010	2009	**2011**	2010	2009
Production Volumes – After Royalties	**1,454**	1,323	1,224	**14.5**	13.2	15.9

2011 versus 2010

Operating Cash Flow of $1,987 million decreased $74 million primarily due to lower realized natural gas prices, lower financial hedging gains, higher transportation expenses and higher operating expenses, partially offset by higher production volumes and higher realized liquids prices. In 2011:

- Average natural gas production volumes of 1,454 MMcf/d increased 131 MMcf/d and average oil and NGL production volumes of 14.5 Mbbls/d increased 1.3 Mbbls/d. This increased revenues $212 million as a result of a successful drilling program across all key resource plays.
- Lower natural gas prices decreased revenues by $165 million, while higher liquids prices increased revenues by $111 million.
- Realized financial hedging gains were $365 million compared to $479 million in 2010 on a before tax basis.
- Transportation expenses increased $53 million due to higher production volumes.
- Operating expenses increased $57 million due to scheduled plant turnaround costs, higher property tax and a higher U.S./Canadian dollar exchange rate, partially offset by lower electricity costs.

2010 versus 2009

Operating Cash Flow of $2,061 million decreased $611 million primarily due to lower financial hedging gains, higher transportation expenses and higher operating expenses, partially offset by higher realized commodity prices and higher natural gas production volumes. In 2010:

- Average natural gas production volumes of 1,323 MMcf/d increased 99 MMcf/d, which increased revenues by $164 million. This increase in volumes is a result of a successful drilling program at Cutbank Ridge and Bighorn and bringing on shut-in and curtailed production.
- Higher natural gas prices increased revenues by $196 million, while higher liquids prices increased revenues by $76 million.
- Realized financial hedging gains were $479 million compared to $1,400 million in 2009 on a before tax basis.
- Transportation expenses increased $43 million and operating expenses increased $41 million due to higher production volumes and a higher U.S./Canadian dollar exchange rate.

2011 Investment Highlights

During 2011, the Canadian Division had capital investment of $2,031 million, land and property acquisitions of $410 million and divestitures of $350 million. Capital investment focused on the development of key resource plays, while land acquisitions focused on capturing acreage with liquids-rich potential.

In December 2011, Encana announced it agreed to sell two natural gas processing plants in the Cutbank Ridge area of British Columbia and Alberta for proceeds of approximately C$920 million. The sale closed on February 9, 2012 and the proceeds were received. As part of the sale, Encana has entered into an agreement for firm gathering and processing services in the Cutbank Ridge area.

Also during 2011, Encana entered into negotiations with Mitsubishi to jointly develop certain undeveloped lands owned by Encana. On February 17, 2012, Encana announced that the Company and Mitsubishi had entered into a partnership agreement for the development of certain Cutbank Ridge undeveloped lands in British Columbia. Under the agreement, Encana will own 60 percent and Mitsubishi will own 40 percent of the partnership. Mitsubishi agreed to initially invest approximately C$1.45 billion on closing and will invest approximately C$1.45 billion in addition to its 40 percent of the partnership's future capital investment for a commitment period, which is expected to be about five years, thereby reducing Encana's capital funding commitments to 30 percent of the total expected capital investment over that period. The transaction does not include any of Encana's current Cutbank Ridge production, processing plants, gathering systems or the Company's Alberta landholdings. The transaction closed on February 24, 2012, and C$1.45 billion was received.

The Canadian Division signed additional deep cut processing arrangements, which will allow the Company to extract additional liquids volumes from its natural gas streams. In 2012, the Company will have access to deep cut processing at the Musreau and Gordondale plants in the Alberta Deep Basin.

Results by Key Area

	Natural Gas Production (MMcf/d)			Oil and NGLs Production (Mbbls/d)			Capital ($ millions)			Drilling Activity (net wells drilled)		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Greater Sierra	**260**	230	199	**0.8**	1.0	0.9	**$ 325**	$ 515	$ 298	**34**	47	57
Cutbank Ridge	**529**	449	371	**3.2**	2.0	1.3	**527**	506	467	**55**	62	71
Bighorn	**230**	220	160	**3.5**	3.2	2.8	**397**	345	272	**40**	51	69
CBM	**433**	395	407	**7.0**	6.0	7.2	**354**	428	313	**596**	1,044	502
Key Resource Plays	**1,452**	1,294	1,137	**14.5**	12.2	12.2	**1,603**	1,794	1,350	**725**	1,204	699
Other	**2**	29	87	**-**	1.0	3.7	**428**	420	519	**2**	2	-
Total Canadian Division	**1,454**	1,323	1,224	**14.5**	13.2	15.9	**$ 2,031**	$ 2,214	$ 1,869	**727**	1,206	699

Other Expenses – Canada Segment

($ millions)	**2011**	2010	2009
Depreciation, depletion and amortization	**$ 966**	$ 826	$ 1,986
Impairments	**2,249**	-	4,814

As Encana follows U.S. GAAP full cost accounting, depletion and impairments are calculated at the country cost centre level and not at the Divisional level. The Canadian cost centre in 2011 and 2010 includes expenses from the Canadian Division. The Canadian cost centre in 2009 includes expenses from the Canadian Division and Canada – Other.

DD&A for 2011 increased $140 million over 2010 primarily due to higher production volumes. DD&A for 2009 of $1,986 million included depletion of the Cenovus upstream assets prior to the Split Transaction.

A non-cash ceiling test impairment was recognized in 2011 for $2,249 million before tax and in 2009 for $4,814 million before tax. Impairments resulted primarily from the decline in the 12-month average trailing natural gas prices. A non-cash ceiling test impairment is recognized when the capitalized costs aggregated at the country cost centre level exceed the sum of the estimated after-tax future net cash flows from proved reserves, using the 12-month average trailing prices and unescalated future development and production costs, discounted at 10 percent, plus unproved property costs.

USA Division

Operating Cash Flow

	Operating Cash Flow ($ millions)			Natural Gas Netback ($/Mcf)			Oil & NGLs Netback ($/bbl)		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Revenues, Net of Royalties, excluding Hedging	**$ 3,424**	$ 3,577	$ 2,525	**$ 4.47**	$ 4.73	$ 3.75	**$ 85.28**	$ 69.35	$ 48.56
Realized Financial Hedging Gain	**598**	698	2,012	**0.87**	1.03	3.41	**-**	-	-
Expenses									
Production and mineral taxes	**183**	209	118	**0.23**	0.27	0.17	**7.54**	6.69	4.39
Transportation	**728**	662	530	**1.06**	0.97	0.90	**0.08**	-	-
Operating	**444**	472	420	**0.62**	0.58	0.53	**0.70**	-	-
Operating Cash Flow/Netback	**$ 2,667**	$ 2,932	$ 3,469	**$ 3.43**	$ 3.94	$ 5.56	**$ 76.96**	$ 62.66	$ 44.17

	Natural Gas (MMcf/d)			Oil & NGLs (Mbbls/d)		
	2011	2010	2009	**2011**	2010	2009
Production Volumes – After Royalties	**1,879**	1,861	1,616	**9.5**	9.6	11.3

2011 versus 2010

Operating Cash Flow of $2,667 million decreased $265 million primarily due to lower realized natural gas prices, lower financial hedging gains and higher transportation expenses, partially offset by higher realized liquids prices and higher natural gas production volumes. In 2011:

- Average natural gas production volumes of 1,879 MMcf/d increased 18 MMcf/d, which increased revenues by $31 million. The increase in volumes was primarily due to a successful drilling program in Haynesville, partially offset by net divestitures and natural declines.
- Lower natural gas prices decreased revenues by $179 million, while higher liquids prices increased revenues by $56 million.
- Realized financial hedging gains were $598 million compared to $698 million in 2010 on a before tax basis.
- Transportation expenses increased $66 million due to transporting volumes further to obtain higher price realizations.

2010 versus 2009

Operating Cash Flow of $2,932 million decreased $537 million primarily due to lower realized financial hedging gains, higher transportation expenses and higher production and mineral taxes, partially offset by higher realized commodity prices and higher natural gas production volumes. In 2010:

- Average natural gas production volumes of 1,861 MMcf/d increased 245 MMcf/d, which increased revenues by $335 million. The increase in volumes was primarily due to a successful drilling program in Haynesville and Piceance and bringing on shut-in and curtailed production.
- Higher natural gas prices increased revenues by $669 million, while higher liquids prices increased revenues by $73 million.
- Realized financial hedging gains were $698 million compared to $2,012 million in 2009 on a before tax basis.
- Transportation expenses increased $132 million due to transporting volumes further to obtain higher price realizations.
- Production and mineral taxes increased $91 million primarily due to higher natural gas prices and a reduction in production tax credits.

2011 Investment Highlights

During 2011, the USA Division had capital investment of $2,446 million, land and property acquisitions of $105 million and divestitures of $1,730 million. Capital investment focused on the development of the Haynesville and Piceance key resource plays, while land acquisitions focused on capturing acreage with liquids-rich potential. The USA Division divestitures included the sales of the Fort Lupton natural gas processing plant, the South Piceance natural gas gathering assets and the majority of the North Texas natural gas producing assets. In the first quarter of 2012, Encana closed the remainder of the sale of the North Texas assets and received additional proceeds of $114 million.

Results by Key Area

	Natural Gas Production *(MMcf/d)*			Oil and NGLs Production *(Mbbls/d)*			Capital *($ millions)*			Drilling Activity *(net wells drilled)*		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Jonah	**471**	531	571	**4.3**	4.6	5.1	**$ 275**	$ 374	$ 346	**71**	112	108
Piceance	**435**	446	362	**1.9**	2.0	1.8	**453**	224	183	**141**	125	129
Texas	**376**	487	470	**0.3**	0.2	0.6	**310**	418	446	**41**	52	65
Haynesville	**508**	287	61	**-**	-	-	**1,018**	1,141	521	**87**	100	48
Key Resource Plays	**1,790**	1,751	1,464	**6.5**	6.8	7.5	**2,056**	2,157	1,496	**340**	389	350
Other	**89**	110	152	**3.0**	2.8	3.8	**390**	345	325	**62**	59	40
Total USA Division	**1,879**	1,861	1,616	**9.5**	9.6	11.3	**$ 2,446**	$ 2,502	$ 1,821	**402**	448	390

Other Expenses – USA Segment

($ millions)	**2011**	2010	2009
Depreciation, depletion and amortization	**$ 1,226**	$ 1,094	$ 1,382
Impairments	**-**	-	6,285

DD&A for 2011 increased $132 million compared to 2010 primarily due to higher production volumes. DD&A for 2010 decreased $288 million compared to 2009 primarily due to a lower DD&A rate as a result of a non-cash ceiling test impairment recognized at December 31, 2009.

At December 31, 2009, a non-cash ceiling test impairment of $6,285 million before tax was recognized primarily due to a decline in the 12-month average trailing natural gas prices. A non-cash ceiling test impairment is recognized when the capitalized costs aggregated at the country cost centre level exceed the sum of the estimated after-tax future net cash flows from proved reserves, using the 12-month average trailing prices and unescalated future development and production costs, discounted at 10 percent, plus unproved property costs.

Canada – Other Division

	Operating Cash Flow ($ millions)			Natural Gas Netback ($/Mcf)			Oil & NGLs Netback ($/bbl)		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Revenues, Net of Royalties, excluding Hedging	**$ -**	$ -	$ 3,239	**$ -**	$ -	$ 3.54	**$ -**	$ -	$ 50.04
Realized Financial Hedging Gain	**-**	-	984	**-**	-	3.29	**-**	-	1.08
Expenses									
Production and mineral taxes	**-**	-	39	**-**	-	0.06	**-**	-	0.65
Transportation	**-**	-	596	**-**	-	0.14	**-**	-	1.58
Operating	**-**	-	626	**-**	-	0.70	**-**	-	11.38
Purchased product	**-**	-	(85)	**-**	-	-	**-**	-	-
Operating Cash Flow/Netback	**$ -**	$ -	$ 3,047	**$ -**	$ -	$ 5.93	**$ -**	$ -	$ 37.51

	Natural Gas (MMcf/d)			Oil & NGLs (Mbbls/d)		
	2011	2010	2009	**2011**	2010	2009
Production Volumes – After Royalties	-	-	762	-	-	99.9

Canada – Other includes the results from the former Canadian upstream operations, which were transferred to Cenovus as part of the November 30, 2009 Split Transaction. Under U.S. GAAP full cost accounting, the historical results are presented in continuing operations.

Market Optimization

($ millions)	**2011**	2010	2009
Revenues	**$ 703**	$ 797	$ 1,607
Expenses			
Operating	**40**	34	26
Purchased product	**635**	739	1,545
Depreciation, depletion and amortization	**12**	11	20
	$ 16	$ 13	$ 16

Market Optimization revenues and purchased product expenses relate to activities that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification. Revenues and purchased product expenses decreased in 2011 compared to 2010 mainly due to lower commodity prices and lower volumes required for optimization. Revenues and purchased product expenses decreased in 2010 compared to 2009 mainly due to lower volumes required for optimization as a result of the Split Transaction, partially offset by higher commodity prices.

Corporate and Other

($ millions)	**2011**	2010	2009
Revenues	**$ 870**	$ 969	$ (2,447)
Expenses			
Operating	**(23)**	(1)	49
Depreciation, depletion and amortization	**78**	77	143
	$ 815	$ 893	$ (2,639)

Revenues mainly includes unrealized hedging gains or losses recorded on natural gas financial derivative contracts which result from the volatility in forward curves of commodity prices and changes in the balance of unsettled contracts between periods. Operating expenses primarily reflect 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 furniture and leasehold improvements.

Discontinued Operations

Encana's 2009 discontinued operations include the former U.S. downstream refining operations, which were transferred to Cenovus as a result of the November 30, 2009 Split Transaction. In 2009, net earnings from discontinued operations was $30 million.

Other Operating Results

Expenses

($ millions)	**2011**	2010	2009
Accretion of asset retirement obligation	**$ 50**	$ 46	$ 71
Administrative	**350**	362	455
Interest	**468**	501	573
Foreign exchange (gain) loss, net	**133**	(251)	(150)
Other	**21**	2	2
	$ 1,022	$ 660	$ 951

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

The 2009 expenses include upstream and corporate costs related to Cenovus operations.

Income Tax

($ millions)	**2011**	2010	2009
Current Income Tax	**$ (195)**	$ (213)	$ 1,878
Deferred Income Tax	**212**	1,189	(5,177)
Income Tax Expense (Recovery)	**$ 17**	$ 976	$ (3,299)

In 2011, current income tax was a recovery of $195 million compared to a recovery of $213 million in 2010 and current tax expense of $1,878 million in 2009. The current income tax recoveries for 2011 and 2010 were primarily due to the carry back of tax losses to prior years. The lower recovery in 2011 compared to 2010 primarily results from current year divestitures, partially offset by lower Cash Flow resulting from lower natural gas prices and lower realized hedging gains. The current income tax recovery in 2010 compared to a current income tax expense of $1,878 million in 2009 was primarily due to lower Cash Flow resulting from lower realized hedging gains, the inclusion of Cenovus results in 2009 and the windup of the Company's Canadian oil and gas partnership in 2009. The lower Cash Flow was partially offset by higher realized commodity prices and higher natural gas production volumes for the Canadian and USA Divisions.

Total income tax expense in 2011 decreased $959 million from 2010 due to lower net earnings before tax primarily resulting from a non-cash ceiling test impairment, lower natural gas prices, lower combined realized and unrealized hedging gains and a foreign exchange loss. Total income tax expense in 2010 increased $4,275 million from 2009 due to the combined impact of realized and unrealized hedging gains, higher realized commodity prices and the inclusion of non-cash ceiling test impairments in 2009 net earnings.

Encana's effective tax rate in any period is a function of total income tax to the amount of net earnings before income tax for the period. The effective tax rate differs from the Canadian statutory tax rate due to permanent differences, jurisdictional tax rates, benefits of loss carrybacks and adjustments to estimates. Permanent differences primarily include the non-taxable portion of capital gains or losses, international financing and the effect of changes in legislation.

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)		2011		2010		2009
Net Cash From (Used In)						
Operating activities	**$**	**3,927**	$	2,329	$	7,824
Investing activities		**(3,631)**		(4,729)		(4,806)
Financing activities		**(194)**		(1,284)		872
Foreign exchange gain (loss) on cash and cash equivalents held in foreign currency		**(1)**		2		19
Increase (Decrease) in Cash and Cash Equivalents	**$**	**101**	$	(3,682)	$	3,909
Cash and Cash Equivalents, End of Year	**$**	**800**	$	699	$	4,381

Operating Activities

Net cash from operating activities in 2011 of $3,927 million increased $1,598 million compared to 2010. Net cash from operating activities in 2010 of $2,329 million decreased $5,495 million compared to 2009. These variances are a result of the Cash Flow variances discussed in the Financial Results section of this MD&A, as well as the changes in non-cash working capital. In 2011, the net change in non-cash working capital was a deficit of $15 million compared to a deficit of $1,998 million in 2010 and a deficit of $276 million in 2009. The 2010 net change in non-cash working capital reflected a one time tax payment of $1,775 million related to the wind-up of the Company's Canadian oil and gas partnership.

The Company had a working capital surplus of $881 million at December 31, 2011 compared to a deficit of $62 million at December 31, 2010. The increase in working capital is primarily the result of higher net risk management assets of $1,141 million which represents the fair value of the Company's unsettled derivative financial instruments.

At December 31, 2011, working capital also included cash and cash equivalents of $800 million and current portion of long-term debt of $492 million compared to $699 million and $500 million, respectively, at December 31, 2010. Encana expects that it will continue to meet the payment terms of its suppliers.

Investing Activities

Net cash used for investing activities in 2011 of $3,631 million decreased $1,098 million compared to 2010. The decrease in investing activities primarily resulted from lower capital expenditures and higher divestiture proceeds, partially offset by an increase in cash in reserve. Cash in reserve includes amounts received from counterparties related to jointly controlled assets and amounts placed in escrow for a possible qualifying like-kind exchange for U.S. income tax purposes.

Net cash used for investing activities in 2010 of $4,729 million decreased $77 million compared to 2009, which included $1,677 million of capital investment related to Cenovus operations. In 2010, capital investment for the Canadian and USA Divisions of $4,716 million increased $1,026 million and net divestitures decreased $687 million compared to 2009. Reasons for these changes are discussed further in the Net Capital Investment section of this MD&A.

Financing Activities

Long-Term Debt

Encana's long-term debt, excluding the current portion, totaled $7,658 million at December 31, 2011 and $7,182 million at December 31, 2010. In addition, Encana's current portion of long-term debt at December 31, 2011 was $492 million compared to $500 million at December 31, 2010. There were no outstanding balances under the Company's commercial paper or revolving credit facilities at December 31, 2011 or December 31, 2010.

On November 14, 2011, Encana completed a public offering in the U.S. of senior unsecured notes in two series totaling $1.0 billion. The first series of $600 million have a coupon rate of 3.90 percent and mature November 15, 2021, and the second series of $400 million have a coupon rate of 5.15 percent and mature November 15, 2041. The proceeds of the offering were used to repay a portion of Encana's commercial paper indebtedness, a portion of which was incurred to repay Encana's $500 million 6.30 percent notes that matured November 1, 2011.

During 2009, in conjunction with the Split Transaction, Cenovus completed a private offering of unsecured notes for net proceeds of $3,468 million. Upon completion of the Split Transaction, Cenovus used the proceeds to settle the Cenovus notes due to Encana.

Credit Facilities and Shelf Prospectuses

Encana maintains two committed revolving bank credit facilities and a Canadian and a U.S. dollar shelf prospectus.

As at December 31, 2011, Encana had available unused committed revolving bank credit facilities of $4.9 billion.

- On October 12, 2011, Encana renewed its revolving bank credit facility for C$4.0 billion ($3.9 billion) that remains committed through October 2015, of which C$4.0 billion ($3.9 billion) remains unused.
- On October 20, 2011, one of Encana's U.S. subsidiaries renewed its revolving bank credit facility for $1.0 billion that remains committed through October 2015, of which $999 million remains unused.

As at December 31, 2011, Encana had available unused capacity under shelf prospectuses for up to $5.0 billion.

- On May 18, 2011, Encana renewed a shelf prospectus whereby it may issue from time to time up to C$2.0 billion, or the equivalent in foreign currencies, of debt securities in Canada. At December 31, 2011, C$2.0 billion ($2.0 billion) of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions. The shelf prospectus expires in June 2013.
- Encana has in place a shelf prospectus whereby it may issue from time to time up to $4.0 billion, or the equivalent in foreign currencies, of debt securities in the U.S. On November 14, 2011, Encana utilized the shelf prospectus to issue senior unsecured notes totaling $1.0 billion in the U.S. At December 31, 2011, $3.0 billion of the shelf prospectus remained unutilized, the availability of which is dependent upon market conditions. The shelf prospectus expires in May 2012, and is expected to be renewed.

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.

Normal Course Issuer Bid

In 2011, 2010 and 2009, Encana had approval from the Toronto Stock Exchange to purchase common shares under a Normal Course Issuer Bid ("NCIB"). Encana was entitled to purchase, for cancellation, up to 36.8 million common shares under the most recent NCIB which commenced on December 14, 2010 and expired on December 13, 2011. The Company has not renewed its NCIB and did not purchase any common shares during 2011. During 2010, the Company purchased approximately 15.4 million common shares for total consideration of approximately $499 million. During 2009, the Company did not purchase any of its common shares.

Dividends

Encana pays quarterly dividends to shareholders at the discretion of the Board of Directors. Dividend payments in 2011 were $588 million, or $0.80 per share (2010 - $590 million or $0.80 per share; 2009 - $1,051 million or $1.40 per share). The Company's quarterly dividend payment in 2011 and 2010 was $0.20 per share. For the first three quarters of 2009, Encana paid a quarterly dividend of $0.40 per share. Following the Split Transaction in the fourth quarter of 2009, Encana paid a quarterly dividend of $0.20 per share.

On February 16, 2012, the Board of Directors declared a dividend of $0.20 per common share which was paid on March 30, 2012.

Outstanding Share Data

As at December 31, 2011, Encana had 736.3 million common shares outstanding (2010 – 736.3 million; 2009 – 751.3 million). As at April 23, 2012, Encana had 736.3 million common shares outstanding.

Eligible employees have been granted stock options to purchase common shares in accordance with Encana's Employee Stock Option Plan. As at December 31, 2011, there were approximately 37.7 million outstanding stock options with associated Tandem Stock Appreciation Rights ("TSARs") attached (21.2 million exercisable). A TSAR gives the holder the conditional right to receive an Encana common share or a cash payment equal to the excess of the market price of Encana's common share at the time of exercise over the exercise price of the TSAR. The exercise of a TSAR for a cash payment does not result in the issuance of any Encana common shares and therefore has no dilutive effect. Historically, most holders of these options have elected to exercise their stock options as a TSAR in exchange for a cash payment.

In 2011, Restricted Share Units ("RSUs") were granted to eligible employees to receive Encana common shares, or the cash equivalent, as determined by Encana, and in accordance with the RSU Plan for Employees of Encana and RSU Grant Agreement. The value of one RSU is notionally equivalent to one Encana common share. As at December 31, 2011, there were approximately 3.3 million outstanding RSUs which vest three years from the date granted. The receipt of a cash payment does not result in the issuance of any Encana common shares and therefore has no dilutive effect. The Company intends to settle vested RSUs in cash on the vesting date.

Capital Structure

The Company's capital structure consists of shareholders' equity plus long-term debt, including the current portion. The Company's objectives when managing its capital structure are to maintain financial flexibility to preserve Encana's access to capital markets and its ability to meet financial obligations and finance internally generated growth, as well as potential acquisitions. Encana has a long-standing practice of maintaining capital discipline, managing its capital structure 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, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt. In managing its capital structure, the Company monitors several non-GAAP financial metrics as indicators of its overall financial strength. The financial metrics the Company currently monitors are below.

(as at December 31)	**2011**	2010	2009
Debt to Debt Adjusted Cash Flow (1)	**1.8x**	1.6x	1.1x
Debt to Adjusted EBITDA (1)	**1.9x**	1.6x	0.9x
Debt to Capitalization (1)	**49%**	45%	49%

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

Contractual Obligations and Contingencies

Contractual Obligations

The following table outlines the contractual obligations, including commitments, of the Company at December 31, 2011.

	Expected Future Payments						
($ millions, undiscounted)	2012	2013	2014	2015	2016	Thereafter	Total
Long-Term Debt [1]	$ 492	$ 500	$ 1,000	$ -	$ -	$ 6,137	$ 8,129
Asset Retirement Obligation	46	47	46	39	34	4,310	4,522
Other Long-Term Obligations	38	90	91	92	93	2,112	2,516
Capital Leases	45	89	89	89	89	310	711
Obligations [2]	621	726	1,226	220	216	12,869	15,878
Transportation and Processing	747	795	856	860	767	5,053	9,078
Purchases of Goods and Services	531	198	128	87	46	72	1,062
Operating Leases	52	47	44	39	33	94	309
Capital Commitments	166	7	7	8	7	80	275
Commitments	1,496	1,047	1,035	994	853	5,299	10,724
Total Contractual Obligations	$ 2,117	$ 1,773	$ 2,261	$ 1,214	$ 1,069	$ 18,168	$ 26,602
Sublease Recoveries	$ (25)	$ (45)	$ (45)	$ (46)	$ (46)	$ (1,045)	$ (1,252)

(1) Principal component only. See Note 16 to the U.S. GAAP Consolidated Financial Statements.

(2) The Company has recorded $10,966 million in liabilities related to these obligations.

Other Long-Term Obligations relates to the 25-year lease agreement with a third-party developer for The Bow office project, which has been recorded as an asset under construction with a corresponding liability of $1,309 million. During 2012, Encana will assume occupancy of The Bow office premises, at which time the Company will commence payments to the third-party developer. Over the 25-year term of the agreement, Encana will depreciate The Bow asset and reduce the accrued liability. At the conclusion of the 25-year term, the remaining asset and corresponding liability will be derecognized. In conjunction with the Split Transaction, Encana has subleased part of The Bow office space to Cenovus. Sublease recoveries include the sublease costs expected to be recovered from Cenovus.

Capital Leases includes the commitment related to the Deep Panuke Production Field Centre, which has been recorded as an asset under construction with a corresponding liability of $607 million. Upon commencement of operations in 2012, Encana will recognize the production facility as a capital lease. Encana's undiscounted contractual payments are limited to $711 million ($564 million discounted).

In addition to the Total Contractual Obligations disclosed above, Encana has made commitments related to its risk management program and the Company has an obligation to fund its defined benefit pension and other post-employment benefit plans. Further information can be found in Notes 21 and 19, respectively, to the U.S. GAAP Consolidated Financial Statements. The Company expects to fund its 2012 commitments from Cash Flow.

Contingencies

Legal Proceedings

The Company is involved in various legal claims and actions arising in the ordinary course of 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 unfavorable outcome were to occur, there exists the possibility of a material adverse impact on the Company's consolidated net earnings or loss in the period in which the outcome is determined. Accruals for litigation and claims are recognized if the Company determines that the loss is probable and the amount can be reasonably estimated. The Company believes it has made adequate provision for such legal claims.

Risk Management

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

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

Issues affecting, or with the potential to affect, Encana's reputation are generally of a strategic nature or emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. Encana takes a proactive approach to the identification and management of issues that affect the Company's reputation and has established consistent and clear policies, procedures, guidelines and responsibilities for identifying and managing these issues.

Encana continues to implement its business model of focusing on developing low-risk and low-cost long-life resource plays, which allows the Company to respond well to market uncertainties. Management adjusts financial and operational risk strategies to proactively respond to changing economic conditions and to mitigate or reduce risk.

Financial Risks

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

Financial risks include, but are not limited to:

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

Encana partially mitigates its exposure to financial risks through the use of various financial instruments and physical contracts. The use of derivative financial instruments is governed under formal policies and is subject to limits established by the Board of Directors. All derivative financial agreements are with major financial institutions in Canada and the U.S. or with 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, in the case of commodities, to the mitigation of price risk to achieve investment returns and growth objectives, while maintaining prescribed financial metrics.

To partially mitigate the commodity price risk, the Company may enter into transactions that fix or set a floor on prices. To help protect against regional price differentials, Encana executes transactions to manage the price differentials between its production areas and various sales points. Further information, including the details of Encana's financial instruments as at December 31, 2011, is disclosed in Note 21 to the U.S. GAAP Consolidated Financial Statements.

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

The Company manages liquidity risk using cash and debt management programs. The Company has access to cash equivalents and a wide range of funding alternatives at competitive rates through commercial paper, debt capital markets and committed revolving bank credit facilities. 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 also minimizes its liquidity risk by managing its capital structure. In managing the capital structure, the Company may adjust capital spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt or repay existing debt.

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

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

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

Operational Risks

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

- reserves and resources replacement;
- capital activities; and
- operating activities.

The Company's ability to operate, generate cash flows, complete projects, and value reserves and resources is subject to financial risks, including commodity prices mentioned above, continued market demand for its products and other risk factors outside of its control, which 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; the availability of drilling and other equipment; the ability to access lands; the ability to access water for hydraulic fracturing operations; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; technology failures; accidents; the availability of skilled labour; and reservoir quality. If Encana fails to acquire or find additional natural gas and liquids reserves and resources, its reserves, resources and production will decline materially from their current levels and, therefore, its cash flows are highly dependent upon successfully exploiting current reserves and resources and acquiring, discovering or developing additional reserves and resources.

To mitigate these risks, as part of the capital approval process, the Company's projects are evaluated on a fully risked basis, including geological risk and engineering risk. In addition, the asset teams undertake a thorough review of previous capital programs to identify key learnings, which often include operational issues that positively and negatively impact project results. Mitigation plans are developed for the operational issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project.

On an annual basis, these results are analyzed for Encana's capital program with the results and identified learnings shared across the Company.

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

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

Safety, Environmental and Regulatory Risks

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

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

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

Hydraulic fracturing processes are strictly regulated by various state and provincial government agencies. Encana meets, and in many cases exceeds, the requirements set out by the regulators. The U.S. and Canadian federal and certain U.S. state and Canadian provincial governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and, with the exception of increased chemical disclosure requirements in many of the jurisdictions in which the Company operates, have not provided specific details with respect to any significant actual, proposed or contemplated changes to the hydraulic fracturing regulatory construct. The U.S. Environmental Protection Agency (the "EPA") has commenced a study of the potential environmental impacts of hydraulic fracturing, including the impacts on drinking water sources and public health. The EPA has also released a draft report outlining the results of its groundwater study at Encana's Pavillion natural gas field in Wyoming. Although the EPA's draft report has not been subject to a qualified, third-party, scientific verification, any implication of a potential connection between hydraulic fracturing and groundwater quality could impact the Company's existing and planned projects as well as impose a cost of compliance.

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

Climate Change

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

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

In British Columbia, effective July 1, 2008, a 'revenue neutral carbon tax' was applied to virtually all fossil fuels, including diesel, natural gas, coal, propane and home heating fuel. The tax applies to combustion emissions and to the purchase or use of fossil fuels within the province. The rate started at C$10 per tonne of carbon equivalent emissions, was C$20 per tonne in 2011 and rises to C$30 per tonne by 2012. The forecast cost of carbon associated with the British Columbia regulations is not material to Encana at this time and is being actively managed.

The American Clean Energy and Security Act ("ACESA") was passed by the U.S. House of Representatives in June 2009 but failed to gain sufficient support in the U.S. Senate in 2010. The ACESA proposed climate change legislation which would have established a GHG cap-and-trade system and provided incentives for the development of renewable energy. Subsequently, the current U.S. Administration has directed the U.S. EPA to exercise new authority under the Clean Air Act to regulate GHG emissions. Under the Clean Air Act, the EPA is required to set industry-specific standards for new and existing sources that emit GHGs above a certain threshold. To date, the EPA has made no significant announcements pertaining to the development or implementation of industry-specific standards related to oil and gas exploration and production. Encana will continue to monitor these developments during 2012.

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 on the following key elements:

- significant production weighting in natural gas;
- focus on energy efficiency and the development of technology to reduce GHG emissions; and
- involvement in the creation of industry best practices.

Encana's strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

- *Manage Existing Costs*. 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.

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

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

Encana monitors developments in emerging climate change policy and legislation, and considers the associated costs of carbon in its strategic planning. Management and the Board of Directors review the impact of a variety of carbon constrained scenarios on its strategy, with a current price range from approximately $10 to $50 per tonne of emissions applied to a range of emissions coverage levels. Encana also examines the impact of carbon regulation on its major projects. Although uncertainty remains regarding potential future emissions regulation, Encana's plan is to continue to assess and evaluate the cost of carbon relative to its investments across a range of scenarios.

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

U.S. GAAP Policies and Estimates

U.S. GAAP Critical 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 U.S. GAAP Consolidated Financial Statements. The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to determining Encana's financial results.

Upstream Assets and Reserves

Encana follows U.S. GAAP full cost accounting for natural gas, oil and NGL activities. Reserves estimates can have a significant impact on net earnings, as they are a key input to the Company's depletion and ceiling test impairment calculations. A downward revision in reserves estimates may increase depletion expense and may also result in a ceiling test impairment. A ceiling test impairment is recognized in net earnings when the carrying amount of a country cost centre exceeds the country cost centre ceiling. The carrying amount of a cost centre includes capitalized costs of proved oil and gas properties, net of accumulated depletion and the related deferred income taxes. The cost centre ceiling is the sum of the estimated after-tax future net cash flows from proved reserves, using the 12-month average trailing prices and unescalated future development and production costs, discounted at 10 percent, plus unproved property costs. Any excess of the carrying amount over the calculated ceiling is recognized as an impairment in net earnings. During 2011 and 2009, Encana recorded ceiling test impairments, which are discussed further in the Divisional Results section of this MD&A.

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

Asset Retirement Obligation

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. 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 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 undiscounted cash flows are recognized as a change in the asset retirement obligation and the related asset retirement cost.

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

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually at December 31. Goodwill and all other assets and liabilities are allocated to reporting units, which are Encana's country cost centres. To assess impairment, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than the fair value then goodwill is written down to the 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. 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, 2011 and has determined that no write-down is required.

Income Taxes

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

Deferred income tax assets are initially recognized and a corresponding valuation allowance is recorded to reduce deferred tax assets to the extent that it is no longer more likely than not that sufficient taxable earnings will be available to allow all or part of the assets to be recovered. Encana routinely assesses deferred tax assets to ensure they are realizable.

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

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

Derivative Financial Instruments

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

Derivative financial instruments are measured at fair value with changes in fair value recognized in net earnings. The fair values recorded in the Consolidated Balance Sheet reflect netting the asset and liability positions where counterparty master netting arrangements contain provisions for net settlement. Realized gains or losses from financial derivatives related to natural gas and oil commodity prices are recognized in revenues as the contracts are settled. Realized gains or losses from financial derivatives related to power commodity prices are recognized in operating costs as the related power contracts are settled. Unrealized gains and losses are recognized in revenues and operating costs 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.

U.S. GAAP Recent Pronouncements Issued

As of January 1, 2012, Encana will be required to adopt the following standards and updates issued by the Financial Accounting Standards Board ("FASB"), which should not have a material impact on the Company's U.S. GAAP Consolidated Financial Statements:

- Accounting Standards Update 2011-04, *Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS,* clarifies and changes existing fair value measurement and disclosure requirements. The amendments will be applied prospectively and will not have a significant impact on the Company's fair value measurements or disclosures.

- Accounting Standards Update 2011-05, *Presentation of Comprehensive Income,* requires that net earnings and comprehensive income be presented either in a single continuous statement or in two separate consecutive statements. As Encana presents its net earnings and comprehensive income in two separate consecutive statements, the amendments will not have an impact on the Company's financial statement presentation. Accounting Standards Update 2011-12, *Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05,* defers the effective date of certain presentation requirements for items reclassified out of accumulated other comprehensive income.

- Accounting Standards Update 2011-08, *Intangibles – Goodwill and Other,* permits an initial assessment of qualitative factors to determine whether the two-step goodwill impairment test is required to be performed as described in Accounting Standards Codification Topic 350, *Intangibles – Goodwill and Other*. The amendments will be applied prospectively.

As of January 1, 2013, Encana will be required to adopt the following standard issued by the FASB, which should not have a material impact on the Company's U.S. GAAP Consolidated Financial Statements:

- Accounting Standards Update 2011-11, *Disclosures about Offsetting Assets and Liabilities,* requires disclosure of both gross and net information about financial instruments eligible for offset in the balance sheet and financial instruments subject to master netting arrangements. The amendments will be applied retrospectively and may expand the Company's financial instruments disclosures.

Non-GAAP Measures

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

Cash Flow

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

	2011					2010					2009
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Cash From (Used in) Operating Activities	**$ 3,927**	**$ 1,005**	**$ 1,285**	**$ 980**	**$ 657**	$ 2,329	$ 901	$ 1,298	$ 911	$ (781)	$ 7,824
(Add back) deduct:											
Net change in other assets and liabilities	**(160)**	**(30)**	**(26)**	**(75)**	**(29)**	(112)	(27)	(16)	(38)	(31)	238
Net change in non-cash working capital from continuing operations	**(15)**	**166**	**130**	**(34)**	**(277)**	(1,998)	11	182	(268)	(1,923)	(276)
Net change in non-cash working capital from discontinued operations	**-**	**-**	**-**	**-**	**-**	-	-	-	-	-	1,100
Cash tax on sale of assets	**(114)**	**(114)**	**-**	**-**	**-**	-	-	-	-	-	-
Cash Flow	**$ 4,216**	**$ 983**	**$ 1,181**	**$ 1,089**	**$ 963**	$ 4,439	$ 917	$ 1,132	$ 1,217	$ 1,173	$ 6,762

Operating Earnings

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

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

In conjunction with adopting U.S. GAAP, the Company has updated its quarterly Operating Earnings definition to calculate income taxes based on the discrete quarter results and exclude income taxes related to divestitures. The estimated annual effective tax rate is significantly impacted by items including tax on divestitures and related pool adjustments, international financing and the non-taxable portions of capital gains or losses. The difference between the discrete method and the estimated annual effective tax rate method is presented as an estimated annual effective tax rate adjustment. The 2011 and 2010 quarterly comparatives have been restated with no impact on annual Operating Earnings.

	2011					2010					2009
($ millions)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**	Annual	Q4	Q3	Q2	Q1	Annual
Net Earnings	**$ 5**	**$ (476)**	**$ 459**	**$ 383**	**$ (361)**	$ 2,343	$ 131	$ 763	$ (132)	$ 1,581	$ (5,524)
After-tax (addition) / deduction:											
Unrealized hedging gain (loss)	**600**	**397**	**273**	**18**	**(88)**	634	(269)	331	(340)	912	(1,792)
Impairments	**(1,687)**	**(1,105)**	**-**	**-**	**(582)**	-	-	-	-	-	(7,612)
Non-operating foreign exchange gain (loss)	**(99)**	**82**	**(325)**	**44**	**100**	235	159	140	(211)	147	287
Estimated annual effective tax rate adjustments	**-**	**(82)**	**122**	**(31)**	**(9)**	-	(1)	(38)	(8)	47	-
Operating Earnings	**$ 1,191**	**$ 232**	**$ 389**	**$ 352**	**$ 218**	$ 1,474	$ 242	$ 330	$ 427	$ 475	$ 3,593

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, as at December 31)	**2011**	2010	2009
Debt	**$ 8,150**	$ 7,682	$ 7,824
Cash Flow	**4,216**	4,439	6,762
Interest Expense, after tax	**344**	360	406
Debt Adjusted Cash Flow	**$ 4,560**	$ 4,799	$ 7,168
Debt to Debt Adjusted Cash Flow	**1.8x**	1.6x	1.1x

Debt to Adjusted EBITDA

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

($ millions, as at December 31)	**2011**	2010	2009
Debt	**$ 8,150**	$ 7,682	$ 7,824
Net Earnings	**5**	2,343	(5,524)
Add (deduct):			
Interest	**468**	501	573
Income tax expense (recovery)	**17**	976	(3,299)
Depreciation, depletion and amortization	**2,282**	2,008	3,531
Impairments	**2,249**	-	11,099
Accretion of asset retirement obligation	**50**	46	71
Foreign exchange (gain) loss, net	**133**	(251)	(150)
Unrealized (gain) loss on risk management	**(879)**	(945)	2,680
Other	**21**	2	2
Net earnings from discontinued operations	**-**	-	(30)
Adjusted EBITDA	**$ 4,346**	$ 4,680	$ 8,953
Debt to Adjusted EBITDA	**1.9x**	1.6x	0.9x

Debt to Capitalization

Debt to Capitalization is a non-GAAP measure monitored by Management as an indicator of the Company's overall financial strength. Capitalization is a non-GAAP measure defined as long-term debt, including the current portion plus shareholders' equity.

($ millions, as at December 31)	**2011**	2010	2009
Debt	**$ 8,150**	$ 7,682	$ 7,824
Shareholders' Equity	**8,578**	9,493	8,002
Capitalization	**$ 16,728**	$ 17,175	$ 15,826
Debt to Capitalization Ratio	**49%**	45%	49%

Advisory

Forward-Looking Statements

In the interest of providing Encana shareholders and potential investors with information regarding the Company and its subsidiaries, including Management's assessment of Encana's and its subsidiaries' future plans and operations, certain statements contained in this document constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of the "safe harbour" provisions of applicable securities legislation. Forward-looking statements are typically identified by words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project", "objective", "strategy", "strives" or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this document include, but are not limited to, statements with respect to: achieving the Company's business objectives of growing its portfolio to produce natural gas, oil and NGLs, maintaining financial strength, optimizing capital investments, continuing to pay a stable dividend; long-term strategy of accelerating value recognition of assets; achieving operating efficiencies, lowering cost structures and success of resource play hub model; balancing near term uncertainty with focused capital investment in building long-term growth capacity; aligning capital investment plus anticipated dividends with expected cash flow generation before divestiture proceeds; attaining additional financial flexibility from proceeds from planned divestitures and joint venture transactions; expected reduction in capital program for drier natural gas plays while directing greater investment towards oil and liquids-rich development and exploration opportunities; increasing its production of oil and NGLs, including expansion of extraction facilities and exploration program; ability to attract third-party investments; ability to expand natural gas markets in North America and potential development of liquefied natural gas export terminal in British Columbia; mitigating cost increases through improving efficiencies and technology innovation; adoption of U.S. GAAP for 2012 financial reporting; completion of transaction agreements with Mitsubishi, including amount of investments, funding commitment and development of otherwise undeveloped natural gas properties; expected completion dates and proceeds from the sale of certain assets; expanding deep cut processing capacities; projections contained in the 2012 Corporate Guidance (including estimates of cash flow including per share, natural gas, oil and NGLs production, capital investment and its allocation, net divestitures, and 2012 estimated sensitivities of cash flow and operating earnings); estimates of proved reserves, before and after royalties, including by product types and locations; potential joint venture transactions and third-party investments; projections relating to the adequacy of the Company's provision for taxes and legal claims; projections with respect to natural gas production from resource plays; the flexibility of capital spending plans and the source of funding therefore; the effect of the Company's risk management program, including the impact of derivative financial instruments; the impact of the changes and proposed changes in laws and regulations, including those relating to hydraulic fracturing, greenhouse gas, carbon and climate change initiatives on the Company's operations and operating costs; projections that the Company has access to cash equivalents and a wide range of funding at competitive rates; the Company's continued compliance with financial covenants under its credit facilities; the Company's ability to pay its creditors, suppliers, commitments and fund its 2012 capital program and pay dividends to shareholders; the effect of the Company's risk mitigation policies, systems, processes and insurance program; the Company's expectations for future Debt to Debt Adjusted Cash Flow, Debt to Adjusted EBITDA and Debt to Capitalization ratios; the expected impact and timing of various accounting pronouncements, rule changes and standards, including IFRS, on the Company and its U.S. GAAP Consolidated Financial Statements; projections that natural gas represents an abundant, secure, long-term supply of energy to meet North American needs. Readers are cautioned not to place undue reliance on forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By their nature, forward-looking statements involve numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These assumptions, risks and uncertainties include, among other things: volatility of, and assumptions regarding natural gas and liquids prices, including substantial or extended decline of the same and their adverse effect on the Company's operations and financial condition and the value and amount of its reserves; assumptions based upon the Company's current guidance; fluctuations in currency and interest rates; risk that the Company may not conclude divestitures of certain assets or other transactions (including third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as "joint ventures") as a result of various conditions not being met; product supply and demand; market competition; risks inherent in the Company's and its subsidiaries' marketing operations, including credit risks; imprecision of reserves estimates and estimates of recoverable quantities of natural gas and liquids from resource plays and other sources not currently classified as proved, probable or possible reserves or economic contingent resources, including future net revenue estimates; marketing margins; potential disruption or unexpected technical difficulties in developing new facilities; unexpected cost increases or technical difficulties in constructing or modifying processing facilities; risks associated with technology; the Company's ability to replace, expand or find additional reserves; hedging activities resulting in realized and unrealized losses; business interruption and casualty losses; risk of the Company not operating all its properties and assets; counterparty risk; downgrade in credit rating and its adverse effects; liability for indemnification obligations to third parties; variability of dividends to be paid; its ability to generate sufficient cash flow from operations to meet its current and future obligations; its ability to access external sources of debt and equity capital; the timing and the costs of well and pipeline construction; the Company's ability to secure adequate product transportation; changes in royalty, tax, environmental, greenhouse gas, carbon, accounting and other laws or regulations or the interpretations of such laws or regulations; political and economic conditions in the countries in which the Company operates; terrorist threats; risks associated with existing and potential future lawsuits and regulatory actions made against the Company; and other risks and uncertainties described from time to time in the reports and filings made with securities regulatory authorities by Encana. Although Encana believes that the expectations represented by such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned that the foregoing list of important factors is not exhaustive. Furthermore, the forward-looking statements contained in this document are made as of the date of this document, and except as required by law, Encana does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Forward-looking information respecting anticipated 2012 Cash Flow is based upon achieving average production in 2012 of natural gas of between 2.8 to 3.1 Bcf/d, liquids of 28 Mbbls/d, commodity prices for natural gas of NYMEX $3.25/Mcf, oil (WTI) $95.00/bbl, U.S./Canadian dollar foreign exchange rate of $1.00 and a weighted average number of outstanding shares for Encana of approximately 736 million. Assumptions relating to forward-looking statements generally include Encana's current expectations and projections made by the Company in light of, and generally consistent with, its historical experience and its perception of historical trends, as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this document.

Encana is required to disclose events and circumstances that occurred during the period to which this MD&A relates that are reasonably likely to cause actual results to differ materially from material forward-looking statements for a period that is not yet complete that Encana has previously disclosed to the public and the expected differences thereto. Such disclosure can be found in Encana's news release dated April 25, 2012, which is available on Encana's website at www.encana.com, on SEDAR at www.sedar.com and EDGAR at www.sec.gov.

Oil and Gas Information

National Instrument 51-101 of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. Prior to 2011, Encana relied upon an exemption from NI 51-101 granted by Canadian securities regulatory authorities to permit it to provide disclosure relating to reserves and other oil and gas information in accordance with U.S. disclosure requirements. Subsequent to the expiry of that exemption, Encana has provided and continues to provide disclosure which complies with the annual disclosure requirements of NI 51-101 in the Company's AIF. The Canadian protocol disclosure is contained in Appendix A and under "Narrative Description of the Business" in the AIF. Encana has obtained an exemption dated January 4, 2011 from certain requirements of NI 51-101 to permit it to provide certain disclosure prepared in accordance with U.S. disclosure requirements, in addition to the Canadian protocol disclosure. The Company's U.S. GAAP U.S. protocol disclosure is included in Note 24 (unaudited) to the Company's U.S. GAAP Consolidated Financial Statements.

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

Natural Gas, Oil and NGLs Conversions

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

Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Resource Play

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

Currency and References to Encana

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

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

Additional Information

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