Encana Corporation

Annual Information Form
February 17, 2011

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Introduction

This is the annual information form of **Encana Corporation** ("Encana" or the "Company") for the year ended December 31, 2010. In this annual information form, unless otherwise specified or the context otherwise requires, reference to "Encana" or to the "Company" includes reference to subsidiaries of and partnership interests held by Encana Corporation and its subsidiaries.

In this annual information form, the term "liquids" is used to represent crude oil and natural gas liquids ("NGLs"). Liquids also include condensate volumes. Certain liquids volumes have been converted to millions of cubic feet equivalent ("MMcfe") or thousands of cubic feet equivalent ("Mcfe") on the basis of one barrel ("bbl") to six thousand cubic feet ("Mcf"). Also, certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the same basis. MMcfe, Mcfe and BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Unless otherwise indicated, all financial information included in this annual information form is determined using Canadian Generally Accepted Accounting Principles ("Canadian GAAP"), which differs from Generally Accepted Accounting Principles in the United States ("U.S. GAAP"). The notes to Encana's annual audited consolidated financial statements contain a discussion of the principal differences between Encana's financial results calculated under Canadian GAAP and under U.S. GAAP.

Readers are directed to the sections titled "Note Regarding Forward-Looking Statements" and "Note Regarding Reserves Data and Other Oil and Gas Information".

Unless otherwise specified, all dollar amounts are expressed in United States ("U.S.") dollars and all references to "dollars", "$" or to "US$" are to U.S. dollars and all references to "C$" are to Canadian dollars.

Corporate Structure

Name and Incorporation

Encana Corporation is incorporated under the *Canada Business Corporations Act* ("CBCA"). Its executive and registered office is located at 1800, 855 - 2nd Street S.W., Calgary, Alberta, Canada T2P 2S5.

On November 30, 2009, Encana completed a corporate reorganization (the "Split Transaction") to split into two independent publicly traded energy companies – Encana Corporation, a natural gas company, and Cenovus Energy Inc. ("Cenovus"), an integrated oil company. In conjunction with the Split Transaction, Encana's articles were amended to make certain changes to its share capital. Further information on the Company's share capital is disclosed under "Description of Share Capital".

Intercorporate Relationships

The following table presents the name, the percentage of voting securities owned and the jurisdiction of incorporation, continuance or formation of Encana's principal subsidiaries and partnerships as at December 31, 2010. Each of these subsidiaries and partnerships had total assets that exceeded 10 percent of the total consolidated assets of Encana or annual revenues that exceeded 10 percent of the total consolidated annual revenues of Encana as at December 31, 2010.

Subsidiaries & Partnerships	Percentage Directly or Indirectly Owned	Jurisdiction of Incorporation, Continuance or Formation
Encana USA Holdings	100	Delaware
3080763 Nova Scotia Company	100	Nova Scotia
Alenco Inc.	100	Delaware
Encana Oil & Gas (USA) Inc.	100	Delaware
Encana Marketing (USA) Inc.	100	Delaware
Encana USA Investment Holdings	100	Delaware

The above table does not include all of the subsidiaries and partnerships of Encana. The assets and annual revenues of unnamed subsidiaries and partnerships in the aggregate did not exceed 20 percent of the total consolidated assets or total consolidated annual revenues as at December 31, 2010.

As a general matter, Encana reorganizes its subsidiaries as required to maintain proper alignment of its business, operating and management structures.

General Development of the Business

Encana was formed in 2002 through the business combination of Alberta Energy Company Ltd. (“AEC”) and PanCanadian Energy Corporation (“PanCanadian”). On November 30, 2009, Encana completed the Split Transaction which resulted in two independent publicly traded energy companies – Encana, a natural gas company, and Cenovus, an integrated oil company.

Encana is a leading North American natural gas producer that is focused on growing its strong portfolio of natural gas resource plays in key basins from northeast British Columbia to east Texas and Louisiana. Encana’s other operations include the transportation and marketing of natural gas and liquids production. All of Encana’s reserves and production are located in North America.

Operating Divisions

Encana employs a decentralized decision making structure and is currently divided into two operating divisions. The operating divisions are:

- Canadian Division, which includes natural gas exploration, development and production assets located in British Columbia and Alberta, as well as the Deep Panuke natural gas project offshore Nova Scotia. 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. Prior to the Split Transaction, the Canadian Division was known as the Canadian Foothills Division.

- USA Division, which includes the natural gas exploration, development and production assets located in the U.S. Five key resource plays are located in the division: (i) Jonah in southwest Wyoming; (ii) Piceance in northwest Colorado; (iii) East Texas in Texas; (iv) Haynesville in Louisiana and Texas; and (v) Fort Worth in Texas.

Encana’s proprietary production is substantially sold by the Midstream, Marketing & Fundamentals Corporate Group, which is focused on enhancing the Company’s netback price. Midstream, Marketing & Fundamentals manages Encana’s market optimization activities, which include third party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

In 2009, the Company formed the Natural Gas Economy team to focus on pursuing the development of expanded natural gas markets in North America, particularly within the areas of power generation and transportation. Due to the technical breakthroughs with natural gas extraction, the commercial resource in North America has grown to a historical high. This abundance improves the longer term affordability and reliability of natural gas for these potential markets. In addition, increased use of natural gas has the potential to yield lower green house gas and volatile organic compound emissions as compared to other fossil fuel use.

For 2010 financial reporting purposes, Encana’s reportable segments were: (i) Canada; (ii) USA; (iii) Market Optimization; and (iv) Corporate and Other. The Canada reportable segment includes the results from the Canadian Division and Canada – Other. Canada – Other includes the upstream results from the former Canadian Plains Division and former Integrated Oil – Canada operations which were transferred to Cenovus as part of the Split Transaction.

Unless otherwise indicated, select financial, production and other operating data for Encana for periods prior to the November 30, 2009 Split Transaction have not been adjusted to remove the results associated with Canada – Other assets which were transferred to Cenovus. The Canada – Other results are reported as continuing operations in accordance with the full cost accounting requirements. The former Integrated Oil – U.S. Downstream Refining operations were also transferred to Cenovus and are reported as discontinued operations for financial reporting purposes.

Recent Developments

The following describes significant events in the development of Encana's business over the last three years. In this section, all divestiture proceeds are provided on a before-tax basis unless otherwise noted.

2010

- In June 2010, Encana and the China National Petroleum Corporation ("CNPC") signed a memorandum of understanding, outlining a framework for the two companies to negotiate a potential joint venture investment. On February 9, 2011, Encana announced the signing of a Co-operation Agreement with PetroChina International Investment Company Limited, a subsidiary of PetroChina Company Limited, that would see PetroChina pay C$5.4 billion to acquire a 50 percent interest in Encana's Cutbank Ridge business assets in British Columbia and Alberta. Under the Co-operation Agreement, the two companies would establish a 50/50 joint venture to develop the assets. CNPC is the controlling shareholder of PetroChina Company Limited.

  The transaction is subject to regulatory approval from Canadian and Chinese authorities, due diligence and the negotiation and execution of various transaction agreements, including the joint venture agreement.

- In the first quarter of 2010, Encana entered into farm-out agreements with Kogas Canada Ltd., a subsidiary of Korea Gas Corporation ("Kogas"), which has agreed to invest approximately C$565 million over three years to earn a 50 percent interest in approximately 154,000 acres of land in Horn River and Montney in the Greater Sierra and Cutbank Ridge key resource plays.

- Encana completed the acquisition of various strategic lands and properties that complement existing assets within Encana's portfolio. In 2010, acquisitions were approximately $592 million in the Canadian Division and $141 million in the USA division.

- Encana completed the divestiture of non-core assets for proceeds of approximately $288 million in the Canadian Division and $595 million in the USA Division.

2009

- On November 30, 2009, Encana completed the Split Transaction resulting in Encana and Cenovus, two independent publicly traded energy companies. The Split Transaction was initially proposed in May 2008 and was designed to enhance long-term value for shareholders by creating two independent and sustainable companies. In October 2008, due to an unusually high level of uncertainty and volatility in the global debt and equity markets, Encana delayed seeking shareholder and court approval for the Split Transaction until there were clear signs that the global financial markets had stabilized. In September 2009, Encana announced plans to proceed with the split.

  In connection with the Split Transaction, Encana entered into an Arrangement Agreement with Cenovus and another subsidiary of Encana dated October 20, 2009 and a Separation and Transition Agreement with Cenovus dated November 20, 2009. The Arrangement Agreement set out the terms and conditions to the arrangement, including the plan of arrangement. The Separation and Transition Agreement set out the mechanics for the separation of the businesses including the dividing of assets, assumption of liabilities and matters governing certain ongoing relationships between Encana and Cenovus, including reciprocal indemnities with respect to the assets and liabilities kept by Encana or transferred to Cenovus.

- Encana completed the divestiture of mature conventional oil and natural gas assets for proceeds of approximately $1,000 million in the Canadian Division, $73 million in the USA Division and $17 million in Canada – Other operations.

2008

- Encana acquired, in several transactions, certain land and mineral interests in Haynesville in Texas and Louisiana for approximately $1,010 million, net to Encana. These acquisitions increased Encana's land position in Haynesville to approximately 435,000 net acres, including approximately 63,000 net mineral acres.

- Encana completed the divestiture of mature, non-core conventional oil and natural gas assets for proceeds of approximately $400 million in the Canadian Division, $251 million in the USA Division and $47 million in Canada – Other operations.

- Encana completed the sale of all of its interests in France and Brazil and withdrew from Qatar.

- In the third quarter of 2008, the Wood River refinery received regulatory approvals to start construction on the Coker and Refinery Expansion ("CORE") project. The Wood River refinery was part of the Downstream Refining assets transferred to Cenovus as part of the Split Transaction.

Narrative Description of the Business

The following map outlines the location of Encana s North American landholdings and key resource plays as at December 31, 2010.

Encana’s operations are focused on exploiting North American long-life natural gas formations, including tight gas, shales and CBM. Encana attempts to identify early-stage, geographically expansive gas-charged basins and then assembles a large land position to try to capture core resource opportunities. Encana then focuses on determining cost efficient means for extracting natural gas through a combination of detailed reservoir studies and pilot testing available and emerging drilling and completions technologies. Encana's manufacturing-style development approach extends over many years. Capital and operating efficiencies are pursued on an ongoing basis and shared across Encana's expansive portfolio.

Encana’s operations are primarily located in Canada and the U.S. All of Encana’s current reserves and production are located in North America.

Canadian Division

The Canadian Division includes natural gas exploration, development and production assets in British Columbia and Alberta, as well as the Deep Panuke natural gas project offshore Nova Scotia. Four key resource plays are located in the Division: (i) Greater Sierra, including Horn River; (ii) Cutbank Ridge in Alberta and British Columbia, including Montney; (iii) Bighorn; and (iv) CBM. The CBM key resource play (Horseshoe Canyon coalbed methane and commingled shallow gas) is located within the Clearwater area. The Canadian Division also manages the offshore Deep Panuke natural gas project in Atlantic Canada. Prior to the Split Transaction, the Canadian Division was the Canadian Foothills Division.

In 2010, the Canadian Division had total capital investment in Canada of approximately $2,211 million and drilled approximately 1,206 net wells. As at December 31, 2010, the Canadian Division had an established land position in Canada of approximately 10.9 million gross acres (9.1 million net acres); of these, approximately 5.8 million gross acres (4.9 million net acres) are undeveloped. The mineral rights on approximately 39 percent of the total net acreage are owned in fee title by Encana, which means that the mineral rights are held by Encana in perpetuity and production is subject to a mineral tax that is generally less than the Crown royalty imposed on production from land where the government owns the mineral rights. The Canadian Division’s 2010 production after royalties averaged approximately 1,402 million cubic feet equivalent per day. The 2010 average production volumes increased over 2009 by approximately 6 percent, or 83 million cubic feet equivalent per day, due to successful drilling programs, as well as bringing on shut-in and curtailed production volumes. The 2010 volumes were lower by approximately 65 million cubic feet equivalent per day due to net divestitures.

The following tables summarize the Canadian Division landholdings, daily production and producing wells as at and for the periods indicated.

Landholdings

(thousands of acres at December 31, 2010)	Developed Acreage		Undeveloped Acreage		Total Acreage		Average Working Interest
	Gross	Net	Gross	Net	Gross	Net	
Greater Sierra	652	619	1,447	1,190	2,099	1,809	86%
Cutbank Ridge	427	332	909	801	1,336	1,133	85%
Bighorn	261	177	401	311	662	488	74%
Clearwater	3,450	2,937	1,978	1,806	5,428	4,743	87%
Atlantic Canada	21	21	55	11	76	32	42%
Other	270	125	1,055	761	1,325	886	67%
Canadian Division	**5,081**	**4,211**	**5,845**	**4,880**	**10,926**	**9,091**	**83%**

Production (Before Royalties)

(average daily)	Natural Gas *(MMcf/d)*		Liquids *(bbls/d)*		Total *(MMcfe/d)*	
	2010	2009	2010	2009	2010	2009
Greater Sierra	241	215	1,214	1,091	248	221
Cutbank Ridge	431	351	1,894	867	442	356
Bighorn	228	177	4,381	4,099	254	201
Clearwater (1)	402	458	6,113	9,343	439	514
Other	79	105	2,141	3,626	92	128
Canadian Division	**1,381**	**1,306**	**15,743**	**19,026**	**1,475**	**1,420**

Note:

(1) The CBM key resource play located within the Clearwater area averaged production of approximately 322 million cubic feet per day in 2010 (320 million cubic feet per day in 2009).

Production (After Royalties)

(average daily)	Natural Gas *(MMcf/d)*		Liquids *(bbls/d)*		Total *(MMcfe/d)*	
	2010	2009	2010	2009	2010	2009
Greater Sierra	230	199	973	871	236	204
Cutbank Ridge	392	310	1,465	591	401	314
Bighorn	219	159	3,252	2,719	239	175
Clearwater (1)	397	453	6,051	9,192	433	508
Other	85	103	1,408	2,507	93	118
Canadian Division	**1,323**	**1,224**	**13,149**	**15,880**	**1,402**	**1,319**

Note:

(1) The CBM key resource play located within the Clearwater area averaged production of approximately 317 million cubic feet per day in 2010 (316 million cubic feet per day in 2009).

Producing Wells

(number of wells at December 31, 2010) (1)	Natural Gas		Crude Oil		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Greater Sierra	1,121	1,064	3	3	1,124	1,067
Cutbank Ridge	832	722	8	2	840	724
Bighorn	422	329	6	2	428	331
Clearwater (2)	10,482	9,621	113	75	10,595	9,696
Other	468	342	120	67	588	409
Canadian Division	**13,325**	**12,078**	**250**	**149**	**13,575**	**12,227**

Notes:

(1) Figures exclude wells capable of producing, but not producing, as of December 31, 2010.
(2) At December 31, 2010, the CBM key resource play had approximately 7,795 gross producing gas wells (7,153 net gas wells).

Key Resource Plays and Activities in the Canadian Division

Greater Sierra

Greater Sierra is a key resource play located in northeast British Columbia. The primary focus is on the continued development of the Devonian Jean Marie formation and the Horn River Devonian shale formation. In 2010, Encana drilled approximately 47 net wells in the area and production after royalties averaged approximately 236 million cubic feet equivalent per day. Production has remained relatively constant over the last five years while Encana has reduced capital expenditures, excluding the Horn River development.

At December 31, 2010, Encana controlled approximately 423,000 gross undeveloped acres (264,000 net undeveloped acres) in the Devonian shale formation of Horn River in northeast British Columbia. Horn River formation shales (Muskwa, Otter Park and Evie) within Encana's focus area are upwards of 500 feet thick. At December 31, 2010, these shales have been evaluated with 90 gross wells (7 vertical and 83 horizontal), 43 of which have been placed on long-term production (1 vertical and 42 horizontal). In 2009, Encana and its partner commenced drilling a larger program of horizontal wells in the Two Island Lake area and constructed a compressor station and 24-inch raw gas transmission pipeline.

At December 31, 2010, Encana held an average 81 percent working interest in 14 production facilities in the area that were capable of processing approximately 715 million cubic feet per day of natural gas. Encana also held a 100 percent working interest in the Ekwan pipeline which has a capacity of approximately 400 million cubic feet per day and transports natural gas from northeast British Columbia to Alberta. As part of its strategy to develop transportation solutions for its Horn River production, Encana has conditionally agreed to sell its Ekwan Pipeline to TransCanada PipeLines Limited. ("TCPL") to form part of TCPL's proposal to build a pipeline that interconnects Horn River to its Alberta pipeline system.

Encana is also the operator of the Cabin Gas Plant, in which it holds an ownership interest. On January 28, 2010, Encana received an environmental assessment certificate for the Cabin Gas Plant from the British Columbia Environmental Assessment Office (EAO) followed by regulatory approvals from the British Columbia Oil and Gas Commission. The plant was approved for up to 800 million cubic feet per day of capacity. Planning and construction of the project is already underway with the first phase having a planned capacity of 400 million cubic feet per day and is expected to be in-service in the second half of 2012. The second phase, which is planned to add an additional 400 million cubic feet per day of capacity, is fully subscribed and undergoing project sanctioning. Once in operation, the plant will receive compressed and dehydrated raw feed gas, containing CO_2 and traces of H_2S. Once processed to meet sales gas specifications, it is expected that the treated gas will be shipped to market via the TCPL pipeline system. On December 10, 2010, Encana issued notification that it will be sending out a request for proposals to companies interested in buying Encana's interest in the Cabin Gas Plant.

Cutbank Ridge

Cutbank Ridge is a key resource play located in the Canadian Rocky Mountain foothills, southwest of Dawson Creek, British Columbia. Key producing horizons in Cutbank Ridge include the Montney, Cadomin and Doig formations. Montney and Cadomin are almost exclusively being developed with horizontal well technology. Significant improvements have been achieved with respect to horizontal well completions with the application of multi-stage hydraulic fracturing. In 2010, Encana drilled approximately 62 net wells in the area and production after royalties averaged approximately 401 million cubic feet equivalent per day.

Encana holds approximately 693,000 net acres covering the deep basin Montney formation, with approximately 244,500 net acres located within Encana's core development area near Dawson Creek, British Columbia. Encana has tested Montney extensively over the last several years and by applying advanced technology has reduced overall development costs significantly, achieving a greater than 80 percent reduction in costs on a completed interval basis over the past four years.

Encana has sour gas processing capacity of approximately 393 million cubic feet per day at its 100 percent owned gas plants at Hythe and Steeprock, with an additional 110 million cubic feet per day of sweet gas processing capacity. Encana also holds a 60 percent working interest in the Sexsmith gas plant, which has sour gas processing capacity of approximately 125 million cubic feet per day and an additional 50 million cubic feet per day of sweet gas processing capacity.

In the fourth quarter of 2010, Encana signed a deep cut processing agreement securing approximately 90 million cubic feet per day of firm processing capacity at Gordondale. The agreement will allow the Company to extract the liquids from its gas stream, thereby capturing more value and enhancing returns.

Bighorn

Bighorn is a key resource play in west central Alberta, with a focus on exploiting multi-zone stacked Cretaceous sands in the Deep Basin. The primary properties in Bighorn are Resthaven, Kakwa, Redrock and Berland. In 2010, Encana drilled approximately 51 net wells in the area and production after royalties averaged approximately 239 million cubic feet equivalent per day.

Encana has a working interest in a number of natural gas plants within Bighorn. The Resthaven plant, in which Encana has an approximately 70 percent working interest, has a capacity of approximately 100 million cubic feet per day. The Kakwa gas plant has a capacity of approximately 60 million cubic feet per day. Encana owns 50 percent of this plant and has firm processing capacity for the remaining 50 percent. Encana holds a 24 percent working interest in the Berland River plant, which has a capacity of approximately 165 million cubic feet per day.

In the fourth quarter of 2010, Encana signed a deep cut processing agreement securing approximately 105 million cubic feet per day of firm processing capacity at Musreau. The agreement will allow the Company to extract the liquids from its gas stream, thereby capturing more value and enhancing returns.

Clearwater

Clearwater extends from the U.S. border to central Alberta. The primary focus of the Clearwater area is the CBM key natural gas resource play which involves Horseshoe Canyon Coals integrated with shallower sands. Within Clearwater, Encana holds approximately 4.7 million net acres with approximately 2.0 million net acres on the Horseshoe Canyon trend. Approximately 75 percent of the total net acreage landholdings are owned in fee title. In 2010, Encana drilled approximately 1,044 net CBM wells and production averaged approximately 317 million cubic feet per day of natural gas from the CBM key resource play.

Atlantic Canada

At December 31, 2010, Encana held an interest in approximately 76,000 gross acres (32,000 net acres) in Atlantic Canada, which includes Nova Scotia and Newfoundland and Labrador. Encana operates five of its eight licenses in these areas and has an average working interest of approximately 42 percent.

Encana is the owner and operator of the Deep Panuke gas field, located offshore Nova Scotia. The Deep Panuke natural gas project involves the installation of the facilities required to produce natural gas from the field, located approximately 250 kilometres southeast of Halifax (on the Scotian shelf). Produced gas will be transported to shore by subsea pipeline and Encana will transport this natural gas via the Maritimes & Northeast Pipeline to a delivery point in eastern Canada. Work has been progressing in anticipation of first production in the second half of 2011.

USA Division

The USA Division includes Encana's natural gas exploration, development and production assets in the Jonah field in southwest Wyoming, the Piceance Basin in northwest Colorado, the East Texas basin in Texas, the Haynesville shale in Louisiana and Texas and the Fort Worth basin in Texas. Five key resource plays are located in the Division: (i) Jonah; (ii) Piceance; (iii) East Texas; (iv) Haynesville; and (v) Fort Worth.

In 2010, the USA Division had total capital investment of approximately $2,499 million and drilled approximately 448 net wells. As at December 31, 2010, the USA Division had an established land position of approximately 3.1 million gross acres (2.6 million net acres). Approximately 2.5 million gross acres were undeveloped (2.1 million net acres), with the majority in Colorado, Texas, Louisiana, Michigan and Wyoming. The USA Division's 2010 production after royalties averaged approximately 1,919 million cubic feet equivalent per day. The 2010 average production volumes increased over 2009 by approximately 14 percent, or 235 million cubic feet equivalent per day, due to operational success in Haynesville and Piceance, as well as bringing on shut-in and curtailed production volumes. The 2010 volumes were lower by approximately 65 million cubic feet equivalent per day due to net divestitures.

The following tables summarize the USA Division landholdings, daily production and producing wells as at and for the periods indicated.

Landholdings	**Developed Acreage**		**Undeveloped Acreage**		**Total Acreage**		**Average Working Interest**
(thousands of acres at December 31, 2010)	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	
Jonah	18	16	116	104	134	120	90%
Piceance	258	239	657	601	915	840	92%
East Texas	100	68	180	162	280	230	82%
Haynesville	110	66	486	284	596	350	59%
Fort Worth	46	44	15	11	61	55	90%
Other	110	77	1,024	916	1,134	993	88%
USA Division	**642**	**510**	**2,478**	**2,078**	**3,120**	**2,588**	**83%**

Production (Before Royalties)	**Natural Gas** *(MMcf/d)*		**Liquids** *(bbls/d)*		**Total** *(MMcfe/d)*	
(average daily)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Jonah	674	727	5,889	6,444	709	766
Piceance	521	421	2,234	2,027	534	434
East Texas	475	449	87	71	475	449
Haynesville	376	87	-	160	376	88
Fort Worth	161	178	240	579	163	181
Other	135	182	3,478	4,672	157	210
USA Division	**2,342**	**2,044**	**11,928**	**13,953**	**2,414**	**2,128**

Production (After Royalties)

(average daily)	Natural Gas (MMcf/d)		Liquids (bbls/d)		Total (MMcfe/d)	
	2010	2009	2010	2009	2010	2009
Jonah	531	571	4,614	5,067	559	601
Piceance	446	362	1,946	1,760	458	373
East Texas	348	324	69	57	348	324
Haynesville	303	70	-	132	303	71
Fort Worth	123	136	184	435	124	139
Other	110	153	2,825	3,866	127	176
USA Division	**1,861**	**1,616**	**9,638**	**11,317**	**1,919**	**1,684**

Producing Wells

(number of wells at December 31, 2010) (1)	Natural Gas		Crude Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
Jonah	1,289	1,135	-	-	1,289	1,135
Piceance	3,261	2,845	3	-	3,264	2,845
East Texas	705	440	3	1	708	441
Haynesville	281	142	2	1	283	143
Fort Worth	670	582	-	-	670	582
Other	1,518	1,139	5	2	1,523	1,141
USA Division	**7,724**	**6,283**	**13**	**4**	**7,737**	**6,287**

Note:

(1) Figures exclude wells capable of producing, but not producing, as of December 31, 2010.

Key Resource Plays and Activities in the USA Division

Jonah

Jonah is a key resource play located in the Green River Basin in southwest Wyoming. Production is from the Lance formation, which contains vertically stacked sands that exist at depths between 8,500 and 13,000 feet. Historically, Encana's operations have been conducted in the over-pressured core portion of the field. In 2008 and 2009, Encana began conducting development in the adjacent normally pressured lands. In 2010, Encana drilled approximately 112 net wells within the core area and production after royalties averaged approximately 559 million cubic feet equivalent per day.

At December 31, 2010, Encana controlled approximately 116,000 undeveloped gross acres (104,000 net acres). Within the over-pressured area, Encana plans to drill the field to ten acre spacing with higher densities in some areas. Outside of the over-pressured area, Encana owns approximately 112,000 undeveloped gross acres, where 40 acre and possibly 20 acre drilling potential exists.

Piceance

Piceance is a key resource play located in northwest Colorado. The basin is characterized by thick natural gas accumulations primarily in the Williams Fork formation. Encana's 2004 acquisition of Tom Brown, Inc. provided a significant amount of the acreage under current development. In addition to Williams Fork, Encana has recently initiated the evaluation phase of the Niobrara formation, a thick shale predominate throughout the basin. At December 31, 2010, Encana controlled approximately 657,000 undeveloped gross acres (601,000 net acres). In 2010, Encana drilled approximately 125 net wells in the area and production after royalties averaged approximately 458 million cubic feet equivalent per day.

Between 2006 and 2010, Encana finalized ten agreements to jointly develop portions of Piceance. During 2010, Encana drilled approximately 159 net wells primarily utilizing third-party funds. For the period of 2011 to 2016, it is expected that Encana will drill approximately 774 net wells which will be partially funded by third-parties under existing agreements.

Compression and processing facilities in Piceance include approximately 2,600 kilometres of pipelines and a processing facility with a capacity of approximately 60 million cubic feet per day. In addition, Encana has access to third-party processing facilities within Piceance.

East Texas

East Texas is a key resource play characterized as a tight gas play with multi-zone targets in the Bossier and Cotton Valley zones. Encana first entered East Texas in 2004 with the acquisition of Tom Brown, Inc. In 2010, Encana drilled approximately 16 net wells in the area and production after royalties averaged approximately 348 million cubic feet equivalent per day.

In 2005, Encana entered the Deep Bossier play through an acquisition of a 30 percent interest in the Leor Energy group's Deep Bossier assets. Subsequently, in 2006, Encana increased this interest to 50 percent. In November 2007, Encana acquired the Leor Energy group's remaining interests in the Deep Bossier play as well as additional East Texas acreage. At December 31, 2010, Encana controlled approximately 180,000 undeveloped gross acres (162,000 net acres).

Haynesville

The Haynesville shale is a key resource play located in Louisiana and Texas. Encana acquired its first leases in 2005, drilled its first three vertical wells in 2006, and has continued to acquire land. In 2007, Encana signed a 50/50 joint exploration agreement with an unrelated party to explore and develop the lands. In 2008, Encana increased its leased acreage in Haynesville to approximately 435,000 net acres through a series of transactions totaling approximately $1,010 million. At the end of 2009, Encana finalized a joint venture with an unrelated party to develop part of Haynesville in East Texas.

In 2010, Encana drilled approximately 106 net wells in the area and production after royalties averaged approximately 303 million cubic feet equivalent per day. Encana's drilling plans through 2010 were focused on land retention and completion optimization. The December 2010 exit rate production for Haynesville was approximately 419 million cubic feet per day. In 2011, it is expected that the majority of planned development activity will focus on the maximization of gas recovery in Haynesville and Mid-Bossier.

At December 31, 2010, Encana controlled approximately 486,000 undeveloped gross acres (284,000 net acres), with the majority of the leaseholds in North Louisiana being located in the DeSoto and Red River parishes. Certain Haynesville undeveloped acreage is subject to leases that will expire over the next several years unless production is established on the acreage held. In 2010, Encana completed the majority of its land retention program.

Fort Worth

Fort Worth is a key resource play located in North Texas, producing from the prolific Barnett shale. Since entering the basin in 2003, Encana has applied horizontal drilling and multi-stage reservoir stimulation to improve performance in this play. In 2010, Encana drilled approximately 30 net wells in the area and production after royalties averaged approximately 124 million cubic feet equivalent per day.

At December 31, 2010, Encana controlled approximately 15,000 undeveloped gross acres (11,000 net acres).

Other Activity

Encana has established a significant land position in the Collingwood shale play located in Michigan. In 2010, Encana acquired approximately 193,000 net acres, bringing the total landholdings to approximately 424,000 net acres.

Market Optimization

Market Optimization activities are managed by Encana's Midstream, Marketing & Fundamentals Corporate Group. Market Optimization is focused on enhancing the netback price of the Company's proprietary production. Market Optimization activities include third-party purchases and sales of product to provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

Natural Gas Marketing

Encana's produced natural gas is primarily marketed to local distribution companies, industrials, other producers, and energy marketing companies. Prices received by Encana are based primarily upon prevailing index prices for natural gas in the region in which it is sold. Prices are impacted by competing fuels in such markets and by regional supply and demand for natural gas.

Encana seeks to mitigate the market risk associated with future cash flows by entering into various risk management contracts relating to produced natural gas. Details of those contracts related to Encana's various risk management positions are found in Note 17 to Encana's audited Consolidated Financial Statements for the year ended December 31, 2010 which are available via the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com.

Other Marketing Activities

Encana sells its crude oil, condensate and NGLs to markets in Canada and the U.S. Sales are normally executed under spot, monthly evergreen and term contracts with delivery to major pipeline/sales hubs at current market prices. In addition, Encana holds interests in two power assets, the Cavalier and Balzac Power Stations, to optimize its electricity costs, particularly in Alberta.

Delivery Commitments

As part of ordinary business operations, Encana has a number of delivery commitments to provide natural gas under existing contracts and agreements. The majority of Encana's production is sold under short term contracts at the relevant market price at the time that the product is sold. As at December 31, 2010, Encana had no material long term physical sales contracts or delivery contracts.

Former Operations

Former operations, referred to as Canada – Other and U.S. Downstream Refining, were transferred to Cenovus as part of the Split Transaction on November 30, 2009. Canada – Other includes the results from the former Canadian Plains Division and former Integrated Oil Division – Canada operations.

Canada – Other

Canada – Other included established natural gas development and production activities in southern Alberta and southern Saskatchewan, crude oil development and production activities in Alberta and Saskatchewan as well as exploration for, and development and production of bitumen using enhanced oil recovery methods in Alberta. Five key resource plays were contained in Canada - Other: (i) Shallow Gas in southeast Alberta and Saskatchewan; (ii) Pelican Lake in northeast Alberta; (iii) Weyburn in Saskatchewan; (iv) Foster Creek in northeast Alberta; and (v) Christina Lake in northeast Alberta. The Foster Creek and Christina Lake enhanced oil recovery projects were part of the integrated oil business created by Encana and ConocoPhillips in January 2007.

For 2009, Canada – Other had capital investment of approximately $848 million (2008 - $1,500 million) and had drilled approximately 639 net wells (2008 - 1,514 net wells). For 2009, natural gas production after royalties was approximately 762 million cubic feet per day (2008 - 905 million cubic feet per day) and liquids production after royalties was approximately 99,900 barrels per day (2008 - 100,250 barrels per day).

Except where indicated otherwise, the financial, production and other operating data for Encana in this annual information form as at dates prior to, or for periods entirely or partly prior to, the Split Transaction have not been adjusted to remove the results associated with Canada – Other (former Canadian Plains Division and former Integrated Oil – Canada operations) assets which were transferred to Cenovus under the Split Transaction. Canada – Other results are reported as continuing operations in accordance with the full cost accounting requirements.

U.S. Downstream Refining

Prior to the Split Transaction, Encana's Integrated Oil Division was comprised of the Integrated Oil – Canada operations and U.S. Downstream Refining operations. U.S. Downstream Refining focused on the refining of crude oil into petroleum and chemical products at the Borger refinery located in Borger, Texas and the Wood River refinery located in Roxana, Illinois. The refineries were acquired through the creation of the integrated oil business between Encana and ConocoPhillips in January 2007. The refineries were 50 percent owned by Encana and operated by ConocoPhillips. U.S. Downstream Refining was transferred to Cenovus as part of the Split Transaction on November 30, 2009.

For 2009, U.S. Downstream Refining had capital investment of approximately $829 million (2008 - $478 million). The expenditures primarily related to the Wood River refinery's CORE project. For the period ended September 30, 2009, the refineries' gross crude oil capacity was approximately 452 thousand barrels per day (year ended December 31, 2008 - 452 thousand barrels per day) and crude utilization was approximately 90 percent (year ended December 31, 2008 - 93 percent).

The U.S. Downstream Refining results prior to the Split Transaction are reported as discontinued operations for financial reporting purposes.

Reserves and Other Oil and Gas Information

Encana is required to provide reserves data prepared in accordance with Canadian securities regulatory requirements, specifically National Instrument 51-101 ("NI 51-101"). Certain reserves and oil and gas information in accordance with Canadian disclosure requirements are contained in ***Appendix A – Canadian Protocol Disclosure of Reserves Data and Other Oil and Gas Information.*** Additional disclosure required by NI 51-101 is included in the preceding sections of this annual information form, and referenced accordingly herein. Select supplemental reserves and other oil and gas information disclosure is provided in accordance with U.S. disclosure requirements in ***Appendix D – U.S. Protocol Disclosure of Reserves Data and Other Oil and Gas Information***. See "Note Regarding Reserves Data and Other Oil and Gas Information".

The practice of preparing production and reserve quantities data under Canadian disclosure requirements (NI 51-101) differs from the U.S. reporting requirements. The primary differences between the two reporting requirements include:

- the Canadian standards require disclosure of proved and probable reserves; the U.S. standards require disclosure of only proved reserves;
- the Canadian standards require the use of forecast prices in the estimation of reserves; the U.S. standards require the use of 12-month average prices which are held constant;
- the Canadian standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis; the U.S standards require disclosure on a net (after royalties) basis;
- the Canadian standards require disclosure of production on a gross (before royalties) basis; the U.S standards require disclosure on a net (after royalties) basis; and
- the Canadian standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. standards.

Since inception, Encana has retained independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of Encana's natural gas and liquids reserves annually. In 2010, Encana's Canadian reserves were evaluated by McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd., and its U.S. reserves were evaluated by Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton.

Encana's Vice-President, Corporate Reserves & Competitor Analysis and five other staff under this individual's direction oversee the preparation of the reserves estimates by the IQREs. Currently this internal staff of four professional engineers, an engineering technologist and a business analyst have combined relevant experience of over 100 years. The Vice-President and other engineering staff are all members of the appropriate provincial or state professional associations and are members of various industry associations such as the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Encana has a Reserves Committee of independent board members which reviews the qualifications and appointment of the IQREs. The Reserves Committee also reviews the procedures for providing information to the evaluators. All booked reserves are based upon annual evaluations by the IQREs. Annually, the Reserves Committee recommends the selection of IQREs to the Board of Directors for its approval.

The evaluations by the IQREs are conducted from the fundamental petrophysical, geological, engineering, financial and accounting data. Processes and procedures are in place to ensure that the IQREs are in receipt of all relevant information. Reserves are estimated based on material balance analysis, decline analysis, volumetric calculations or a combination of these methods, in all cases having regard to economic considerations. In the case of producing reserves, the emphasis is on decline analysis where volumetric analysis is considered to limit forecasts to reasonable levels. Non-producing reserves are estimated by analogy to producing offsets, with consideration of volumetric estimates of in place quantities.

Acquisitions, Divestitures and Capital Expenditures

Encana's growth in recent years has been achieved through a combination of internal growth and acquisitions. Encana has a large inventory of internal growth opportunities and also continues to examine select acquisition opportunities to develop and expand its key resource plays. The acquisition opportunities may include corporate or asset acquisitions. Encana may finance any such acquisitions with debt, equity, cash generated from operations, proceeds from asset divestitures or a combination of these sources.

The following table summarizes Encana's net capital investment for 2010, 2009 and 2008.

($ millions)	**2010**	**2009**	**2008**
Capital Investment			
Canadian Division	2,211	1,869	2,459
USA Division	2,499	1,821	2,682
	4,710	3,690	5,141
Market Optimization	2	2	17
Corporate & Other	61	85	165
	4,773	3,777	5,323
Acquisitions			
Property			
Canadian Division	592	190	151
USA Division (1)	141	46	1,023
Corporate			
Canadian Division (2)	-	24	-
Divestitures			
Property (3)			
Canadian Division	(288)	(1,000)	(400)
USA Division	(595)	(73)	(251)
Corporate & Other	-	(5)	(41)
Corporate			
Corporate & Other (4)	-	(83)	(165)
	4,623	2,876	5,640
Former Operations (Canada – Other) (5)			
Capital Investment	-	848	1,500
Acquisitions – Property	-	3	-
Divestitures – Property	-	(17)	(47)
Net Capital Investment Before Discontinued Operations	4,623	3,710	7,093
Discontinued Operations (6)	-	829	478
Net Capital Investment	**4,623**	**4,539**	**7,571**

Notes:

(1) In 2008, mainly includes Haynesville properties.
(2) Acquisition of Kerogen Resources Canada, ULC in May 2009.
(3) Primarily includes divestitures of non-core assets.
(4) In 2009, includes the sale of Senlac Oil Limited. In 2008, mainly includes the sale of interests in Brazil.
(5) Canada – Other assets (former Canadian Plains and former Integrated Oil – Canada assets) were transferred to Cenovus as part of the Split Transaction.
(6) Includes U.S. Downstream Refining capital investments, which are reported as discontinued operations as these assets were transferred to Cenovus as part of the Split Transaction.

Competitive Conditions

All aspects of the oil and gas industry are highly competitive and Encana actively competes with natural gas and other companies, particularly in the following areas: (i) exploration for and development of new sources of natural gas and liquids reserves; (ii) reserves and property acquisitions; (iii) transportation and marketing of natural gas, liquids, diluents and electricity; (iv) access to services and equipment to carry out exploration, development or operating activities; and (v) attracting and retaining experienced industry personnel. The oil and gas industry also competes with other industries focused on providing alternative forms of energy to consumers. Competitive forces can lead to cost increases or result in an oversupply of natural gas and liquids, both of which could have a negative impact on Encana's financial results.

Environmental Protection

Encana's operations are subject to laws and regulations concerning pollution, protection of the environment and the handling and transport of hazardous materials. These laws and regulations generally require Encana to remove or remedy the effect of its activities on the environment at present and former operating sites, including dismantling production facilities and remediating damage caused by the use or release of specified substances. The Corporate Responsibility, Environment, Health and Safety Committee of Encana's Board of Directors reviews and recommends environmental policy to the Board of Directors for approval and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety ("EH&S") performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. Contingency plans are in place for a timely response to an environmental event and remediation/reclamation programs are in place and utilized to restore the environment.

Encana monitors developments in emerging climate change policy and legislation, and considers the associated costs of carbon in its strategic planning. The Corporate Responsibility, Environment, Health and Safety Committee of Encana's Board of Directors reviews the impact of a variety of carbon constrained scenarios on Encana's strategy with a current price range from approximately $10 to $50 per tonne of emissions, applied to a range of emissions coverage levels.

Encana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. In 2010, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were not material. Based on Encana's current estimate, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of the reserves is estimated at approximately $4.7 billion. As at December 31, 2010, Encana has recorded an asset retirement obligation of $820 million.

Social and Environmental Policies

Encana has a Corporate Responsibility Policy, an Environment Policy and a Health & Safety Policy (the "Policies") that articulate Encana's commitment to responsible development. The Policies apply to any activity undertaken by or on behalf of Encana, anywhere in the world, associated with the finding, development, production, transmission and storage of the Company's products including decommissioning of facilities, marketing and other business and administrative functions.

The Corporate Responsibility Policy articulates Encana's commitment to conducting its business ethically, legally and in a manner that is fiscally, environmentally and socially responsible, while delivering strong financial performance. The Corporate Responsibility Policy has specific requirements in areas related to: (i) governance; (ii) people; (iii) environment; (iv) health and safety; (v) engagement; and (vi) community involvement.

With respect to Encana's relationship with the communities in which it does business, the Corporate Responsibility Policy states that Encana will: (i) strive to be a good neighbour by contributing to the well-being of the communities where it operates, recognizing their differing priorities and needs; (ii) engage, listen and work with stakeholders in a timely, respectful and meaningful way; and (iii) align its community investments with its business strategy and seek to provide mutually beneficial relationships with the community and non-governmental organizations.

With respect to human rights, the Corporate Responsibility Policy states that Encana will (i) abide by all applicable workplace, employment, privacy and human rights legislation; and (ii) provide a respectful, inclusive workplace free from harassment, discrimination and intimidation.

The Environment Policy recognizes that responsible environmental practices contribute to long-term shareholder value creation and articulates Encana's commitment to environmental stewardship. The Environment Policy outlines specific requirements in areas related to (i) compliance with environmental laws and regulations; (ii) environmental risk assessment and mitigation; (iii) air emissions management; (iv) water sourcing, handling and disposal; (v) pollution prevention and waste minimization; and (vi) habitat, plant and wildlife disturbance.

The Health & Safety Policy recognizes that all occupational injuries and illnesses are preventable and states Encana's goal of achieving a workplace free of recognized hazards, occupational injuries and illnesses.

The Policies and any revisions are approved by Encana's Executive Team and its Board of Directors. Accountability for implementation of the Policies is at the operational level within Encana's business units. Business units have established processes to evaluate risks and programs have been implemented to minimize those risks. Coordination and oversight of the Policies resides with the EH&S, Security and Corporate Responsibility Group within Corporate Development, EH&S and Reserves.

Some of the steps that Encana has taken to embed the corporate responsibility approach throughout the organization include: (i) a comprehensive approach to training and communicating policies and practices and a requirement for acknowledgement and sign-off on key policies from the Board of Directors and employees; (ii) an EH&S management system; (iii) a security program to regularly assess security threats to business operations and to manage the associated risks; (iv) a formalized approach to stakeholder relations with a standardized Stakeholder Engagement Guide and specific Aboriginal Community Engagement Guide; (v) corporate responsibility performance metrics to track the Company's progress; (vi) an environmental efficiency program that focuses on reducing energy and water use at Encana's operations and supports initiatives at the community level while also incenting employees to reduce energy and water use in their homes; (vii) a comprehensive community investment program that contributes to charitable and non-profit organizations in the communities in which Encana operates and an employee program that matches employee donations up to $25,000 per employee, per year; (viii) an Investigations Practice and an Investigations Committee to review and resolve potential violations of Encana policies or practices and other regulations; (ix) an Integrity Hotline that provides an additional avenue for Encana's stakeholders to raise their concerns as well as the corporate responsibility website which allows people to write to the Company about non-financial issues of concern; (x) an internal corporate EH&S audit program that evaluates Encana's compliance with the expectations and requirements of the EH&S management system; and (xi) related policies and practices such as an Alcohol and Drug Policy, a Business Conduct & Ethics Practice and guidelines for correct behaviors with respect to the acceptance of gifts, conflicts of interest and the appropriate use of Encana equipment and technology in a manner that is consistent with leading ethical business practices. In addition, Encana's Board of Directors approves such policies, and is advised of significant contraventions thereof, and receives updates on trends, issues or events which could have a significant impact on the Company.

Employees

At December 31, 2010, Encana employed 4,169 full time equivalent employees (“FTE”) as set forth in the following table.

	FTE Employees
Canadian Division	1,808
USA Division	1,722
Corporate	639
Total	**4,169**

The Company also engages a number of contractors and service providers.

Foreign Operations

As at December 31, 2010, 100 percent of Encana’s reserves and production were located in North America, which limits Encana’s exposure to risks and uncertainties in countries considered politically and economically unstable. Any operations and related assets outside North America may be adversely affected by changes in governmental policy, social instability or other political or economic developments which are not within the control of Encana, including the expropriation of property, the cancellation or modification of contract rights and restrictions on repatriation of cash.

Directors and Officers

The following information is provided for each director and executive officer of Encana as at the date of this annual information form.

Directors

Name & Municipality of Residence	Director Since [1]	Principal Occupation
David P. O'Brien, O.C. [5,7,10] Calgary, Alberta, Canada	1990	Chairman Encana Corporation Chairman Royal Bank of Canada
Peter A. Dea [3,6] Denver, Colorado, U.S.A.	2010	President & Chief Executive Officer Cirque Resources LP *(Private oil & gas company)*
Randall K. Eresman [8] Calgary, Alberta, Canada	2006	President & Chief Executive Officer Encana Corporation
Claire S. Farley [3,5,6] Houston, Texas, U.S.A.	2008	Co-Founder RPM Energy LLC *(Private oil & gas company)*
Fred J. Fowler [3,4] Houston, Texas, U.S.A.	2010	Corporate Director
Barry W. Harrison [2,4,5,9] Calgary, Alberta, Canada	1996	Corporate Director and Independent Businessman
Suzanne P. Nimocks [2,4] Houston, Texas, U.S.A.	2010	Corporate Director
Jane L. Peverett [2,5,6] West Vancouver, British Columbia, Canada	2003	Corporate Director
Allan P. Sawin [2,4] Edmonton, Alberta, Canada	2007	President Bear Investments Inc. *(Private investment company)*
Bruce G. Waterman [2,4] Calgary, Alberta, Canada	2010	Senior Vice President, Finance & Chief Financial Officer Agrium Inc. *(Public agriculture supply company)*
Clayton H. Woitas [3,6] Calgary, Alberta, Canada	2008	Chairman & Chief Executive Officer Range Royalty Management Ltd. *(Private oil & gas company)*

Notes:

(1) Denotes the year each individual became a director of Encana or one of its predecessor companies (AEC or PanCanadian).
(2) Member of Audit Committee.
(3) Member of Corporate Responsibility, Environment, Health and Safety Committee.
(4) Member of Human Resources and Compensation Committee.
(5) Member of Nominating and Corporate Governance Committee.
(6) Member of Reserves Committee.
(7) Ex officio non-voting member of all other committees. As an ex officio non-voting member, Mr. O'Brien attends as his schedule permits and may vote when necessary to achieve a quorum.
(8) As an officer of Encana and a non-independent director, Mr. Eresman is not a member of any Board committees.

(9) Mr. Harrison was a director of Gauntlet Energy Corporation in June 2003 when it filed for and was granted an order pursuant to the *Companies' Creditors Arrangement Act* (Canada). A plan of arrangement for that company received court confirmation later that year.

(10) Mr. O'Brien resigned as a director of Air Canada on November 26, 2003. On April 1, 2003, Air Canada obtained an order from the Ontario Superior Court of Justice providing creditor protection under the *Companies' Creditors Arrangement Act* (Canada). Air Canada also made a concurrent petition under Section 304 of the U.S. Bankruptcy Code. On September 30, 2004, Air Canada announced that it had successfully completed its restructuring process and implemented its Plan of Arrangement.

Encana does not have an Executive Committee of its Board of Directors.

At the date of this annual information form, there are 11 directors of the Company. All of the current directors were elected at the last annual and special meeting of shareholders held on April 21, 2010. At the next annual meeting, shareholders will be asked to elect as directors the 11 individuals listed in the above table. Subject to mandatory retirement age restrictions, which have been established by the Board of Directors, whereby a director may not stand for re-election at the first annual meeting after reaching the age of 71, all of the existing directors shall be eligible for re-election.

Executive Officers

Name & Municipality of Residence	**Corporate Office *(Divisional Title)***
Randall K. Eresman Calgary, Alberta, Canada	President & Chief Executive Officer
Sherri A. Brillon Calgary, Alberta, Canada	Executive Vice-President & Chief Financial Officer
Michael M. Graham Calgary, Alberta, Canada	Executive Vice-President (*President, Canadian Division*)
Robert A. Grant Calgary, Alberta, Canada	Executive Vice-President, Corporate Development, EH&S and Reserves
Eric D. Marsh Denver, Colorado, U.S.A.	Executive Vice-President, Natural Gas Economy *(Senior Vice-President, USA Division)*
Michael G. McAllister Calgary, Alberta, Canada	Executive Vice-President *(Senior Vice-President, Canadian Division)*
R. William Oliver Calgary, Alberta, Canada	Executive Vice-President & Chief Corporate Officer
William A. Stevenson Calgary, Alberta, Canada	Executive Vice-President & Chief Accounting Officer
Jeff E. Wojahn Denver, Colorado, U.S.A.	Executive Vice-President (*President, USA Division*)
Renee E. Zemljak Denver, Colorado, U.S.A.	Executive Vice-President, Midstream, Marketing & Fundamentals

During the last five years, all of the directors and executive officers have served in various capacities with Encana or its predecessor companies or have held the principal occupation indicated opposite their names except for the following:

Mr. Dea has been President & Chief Executive Officer of Cirque Resources LP (a private oil and gas company) since May 2007. From November 2001 through August 2006, he was President & Chief Executive Officer and a director of Western Gas Resources, Inc. (a public natural gas company).

Ms. Farley is a co-founder of RPM Energy LLC (a privately-owned oil and gas exploration and development company) created in September 2010. She was an Advisory Director of Jefferies Randall & Dewey (a private global oil and gas energy industry advisor) from August 2008 to September 2010 and was Co-President of Jefferies Randall & Dewey from February 2005 to August 2008. She was a Managing Partner of Castex Energy Partners (a private exploration and production limited partnership) from August 2008 to January 2009.

Mr. Fowler has been Chairman of Spectra Energy Partners, LP (a public entity) since October 2008. He was President & Chief Executive Officer of Spectra Energy Corp. (a natural gas gathering, processing and mainline transportation company) from December 2006 to December 2008 and served as a director from December 2006 to May 2009. He was President & Chief Executive Officer of Duke Energy Gas Transmission, LLC (a subsidiary of Duke Energy Corporation) from April 2006 through December 2006. From June 1997, he occupied various executive positions with Duke Energy Corporation (a public oil and gas company), including President and Chief Operating Officer from November 2002 to April 2006.

Ms. Nimocks was a director (senior partner) with McKinsey & Company (a private global management consulting firm) from June 1999 to March 2010 and was with the firm in various other capacities since 1989, including as a leader in the firm's Global Petroleum Practice, Electric Power & Natural Gas Practice, Organization Practice, and Risk Management Practice, as a member of the firm's worldwide personnel committees for many years and as the Houston Office Manager for eight years.

Ms. Peverett was President and Chief Executive Officer of BC Transmission Corporation (electrical transmission) from April 2005 to January 2009.

Mr. Sawin is President of Bear Investments Inc. (a private investment company). From 1990 until their sale to CCS Income Trust in May 2006, he was President, director and part owner of Grizzly Well Servicing Inc. and related companies (private oilfield service companies operating drilling and service rigs in Western Canada).

All of the directors and executive officers of Encana listed above beneficially owned, as of February 10, 2011, directly or indirectly, or exercised control or direction over an aggregate of 573,459 common shares representing 0.08 percent of the issued and outstanding voting shares of Encana, and directors and executive officers held options to acquire an aggregate of 4,360,694 additional common shares.

Investors should be aware that some of the directors and officers of the Company are directors and officers of other private and public companies. Some of these private and public companies may, from time to time, be involved in business transactions or banking relationships which may create situations in which conflicts might arise. Any such conflicts shall be resolved in accordance with the procedures and requirements of the relevant provisions of the CBCA, including the duty of such directors and officers to act honestly and in good faith with a view to the best interests of the Company.

Audit Committee Information

The full text of the Audit Committee mandate is included in Appendix E of this annual information form.

Composition of the Audit Committee

The Audit Committee consists of five members, all of whom are independent and financially literate in accordance with the definitions in National Instrument 52-110 *Audit Committees.* The relevant education and experience of each Audit Committee member is outlined below.

Barry W. Harrison

Mr. Harrison holds a Bachelor of Business Administration and Banking (Colorado College) and a Bachelor of Laws (University of British Columbia). He is a Corporate Director and an independent businessman. Mr. Harrison is Chairman and a director of The Wawanesa Mutual Insurance Company (a Canadian property and casualty insurer) and its related companies, The Wawanesa Life Insurance Company and its U.S. subsidiary, Wawanesa General Insurance Company, operating in California and Oregon. In the past ten years, he has served as either the Chairman, director or President of several intermediate or junior oil & gas companies doing business in Canada, the United States and Russia. Mr. Harrison is also a director and President of Yokara Management Inc. (a private investment company).

Suzanne P. Nimocks

Ms. Nimocks holds a Bachelor of Arts in Economics (Tufts University) and a Masters in Business Administration (Harvard Graduate School of Business). She is a Corporate Director. Ms. Nimocks is a director of Rowan Companies, Inc. (a public international contract drilling services company) and ArcelorMittal (a public international steel company). She was a director (senior partner) with McKinsey & Company (a private global management consulting firm) from June 1999 to March 2010 and was with the firm in various other capacities since 1989, including as a leader in the firm's Global Petroleum Practice, Electric Power & Natural Gas Practice, Organization Practice, and Risk Management Practice, as a member of the firm's worldwide personnel committees for many years and as the Houston Office Manager for eight years.

Jane L. Peverett (Audit Committee Chair)

Ms. Peverett holds a Bachelor of Commerce (McMaster University) and a Master of Business Administration (Queen's University), together with a designation as a Certified Management Accountant and a Canadian Security Analyst Certificate. She is also a Fellow of The Society of Management Accountants (FCMA). Ms. Peverett is a Corporate Director. She is a director of Northwest Natural Gas Company (a public natural gas distribution company), Canadian Imperial Bank of Commerce (one of Canada's largest banks), the B.C. Ferry Authority, and Associated Electric & Gas Insurance Services Limited (a private mutual insurance company). She is also an Audit Committee member of Canadian Imperial Bank of Commerce and Northwest Natural Gas Company. She was President and Chief Executive Officer of BC Transmission Corporation ("BCTC") (electrical transmission) from April 2005 to January 2009 and was previously Vice President, Corporate Services and Chief Financial Officer of BCTC from June 2003 to April 2005. In her 15-year career with the Westcoast Energy Inc./Duke Energy Corporation group of companies, she held senior executive positions with Union Gas Limited (Ontario), including President, President and Chief Executive Officer, Senior Vice President Sales & Marketing and Chief Financial Officer, among others.

Allan P. Sawin

Mr. Sawin holds a Bachelor of Commerce (University of Alberta) and a designation as a Chartered Accountant (Alberta). He is President of Bear Investments Inc. (a private investment company). From 1990 until their sale to CCS Income Trust in May 2006, Mr. Sawin was President, director and part owner of Grizzly Well Servicing Inc. and related companies (private oilfield service companies). From 1995 to 2003, he also served as a director and member of the Audit Committee of NQL Drilling Tools Inc. while it was a public company listed on the Toronto Stock Exchange.

Bruce G. Waterman

Mr. Waterman holds a Bachelor of Commerce (Queen's University) and a designation as a Chartered Accountant. He has been the Senior Vice-President, Finance & Chief Financial Officer of Agrium Inc., (a public agricultural supply company) since April 2000. Prior to joining Agrium, Mr. Waterman was the Vice-President & Chief Financial Officer of Talisman Energy Inc. (a public oil and gas company) from January 1996 to April 2000. Mr. Waterman also has extensive expertise in oil and gas exploration and production operations, having spent 15 years (1981 to 1996) at Amoco Corporation, including Dome Petroleum Limited, a predecessor company. At Amoco (a global chemical, oil and gas company which merged with British Petroleum in 1998), his roles included various positions in finance and accounting.

The above list does not include David P. O'Brien who is an ex officio member of the Audit Committee.

Pre-Approval Policies and Procedures

Encana has adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP. The Audit Committee of the Board of Directors has established a budget for the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by PricewaterhouseCoopers LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee, but at the option of the Audit Committee it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve; and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

Subject to the next paragraph, the Audit Committee has delegated authority to the Chair of the Audit Committee (or if the Chair is unavailable, any other member of the Committee) to pre-approve the provision of permitted services by PricewaterhouseCoopers LLP which have not otherwise been pre-approved by the Audit Committee, including the fees and terms of the proposed services ("Delegated Authority"). All pre-approvals granted pursuant to Delegated Authority must be presented by the member(s) who granted the pre-approvals to the full Audit Committee at its next meeting.

The fees payable in connection with any particular service to be provided by PricewaterhouseCoopers LLP that has been pre-approved pursuant to Delegated Authority (i) may not exceed C$200,000, in the case of pre-approvals granted by the Chairman of the Audit Committee; and (ii) may not exceed C$50,000, in the case of pre-approvals granted by any other member of the Audit Committee.

All proposed services, or the fees payable in connection with such services, that have not already been pre-approved must be pre-approved by either the Audit Committee or pursuant to Delegated Authority. Prohibited services may not be pre-approved by the Audit Committee or pursuant to Delegated Authority.

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by PricewaterhouseCoopers LLP during fiscal 2010 and 2009.

(C$ thousands)	**2010**	**2009**
Audit Fees [1]	3,243	3,963
Audit-Related Fees [2]	252	1,076
Tax Fees [3]	600	569
All Other Fees [4]	15	5
Total	**4,110**	**5,613**

Notes:

(1) Audit fees consist of fees for the audit of the Company's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported as Audit Fees. During fiscal 2010 and 2009, the services provided in this category included an audit and reviews of Cenovus carve-out consolidated financial statements and related documents, reviews in connection with acquisitions and divestitures, research of accounting and audit-related issues, review of reserves disclosure and the review of the Corporate Responsibility Report.

(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2010 and 2009, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns.

(4) During fiscal 2010 and 2009, the services provided in this category included the payment of maintenance fees associated with a research tool that grants access to a comprehensive library of financial reporting and assurance literature and a working paper documentation package used by the Company's internal audit group.

Encana did not rely on the *de minimus* exemption provided by Section (c)(7)(i)(C) of Rule 2-01 of Securities and Exchange Commission ("SEC") Regulation S-X in 2009 or 2010.

Description of Share Capital

The Company is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As of December 31, 2010, there were approximately 736 million common shares outstanding and no preferred shares outstanding.

Common Shares

The holders of the common shares are entitled to receive dividends if, as and when declared by the Board of Directors of the Company. The holders of the common shares are entitled to receive notice of and to attend all meetings of shareholders and are entitled to one vote per common share held at all such meetings. In the event of the liquidation, dissolution or winding up of the Company or other distribution of assets of the Company among its shareholders for the purpose of winding up its affairs, the holders of the common shares will be entitled to participate rateably in any distribution of the assets of the Company.

Encana has stock-based compensation plans that allow employees to purchase common shares of the Company. Option exercise prices approximate the market price for the common shares on the date that the options were issued. Options granted under the plans are generally fully exercisable after three years and expire five years after the grant date.

The November 30, 2009 Split Transaction was effected by way of an arrangement under the CBCA, under which the holders of common shares of Encana received one new Encana common share and one common share of Cenovus for each Encana common share previously held. Holders of the stock options of Encana became the holders of stock options of Encana and Cenovus, with the exercise price under the stock options being adjusted based on the relative trading prices of the Encana and Cenovus common shares.

The Company has a shareholder rights plan (the "Plan") that was adopted to ensure, to the extent possible, that all shareholders of the Company are treated fairly in connection with any take-over bid for the Company. The Plan creates a right that attaches to each present and subsequently issued common share. Until the separation time, which typically occurs at the time of an unsolicited take-over bid, whereby a person acquires or attempts to acquire 20 percent or more of Encana's common shares, the rights are not separable from the common shares, are not exercisable and no separate rights certificates are issued. Each right entitles the holder, other than the 20 percent acquirer, from and after the separation time and before certain expiration times, to acquire one common share at 50 percent of the market price at the time of exercise. The Plan was amended and reconfirmed at the 2010 annual and special meeting of shareholders and must be reconfirmed at every third annual meeting thereafter.

Preferred Shares

Preferred shares may be issued in one or more series. The Board of Directors may determine the designation, rights, privileges, restrictions and conditions attached to each series of preferred shares before the issue of such series. Holders of the preferred shares are not entitled to vote at any meeting of the shareholders of the Company, but may be entitled to vote if the Company fails to pay dividends on that series of preferred shares. The first preferred shares are entitled to priority over the second preferred shares and the common shares of the Company, and the second preferred shares are entitled to priority over the common shares of the Company, with respect to the payment of dividends and the distribution of assets of the Company in the event of any liquidation, dissolution or winding up of the Company's affairs.

Credit Ratings

The following information relating to Encana's credit ratings is provided as it relates to Encana's financing costs and liquidity. Specifically, credit ratings affect Encana’s ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Encana to engage in certain collateralized business activities on a cost effective basis depends on the Company maintaining competitive credit ratings. A reduction in the current ratings on the Company's debt by its rating agencies, particularly a downgrade below investment grade ratings, could adversely affect the Company’s cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect the Company’s ability to, and the associated costs of, entering into normal course derivative or hedging transactions.

The following table outlines the ratings and outlooks of the Company’s debt as of December 31, 2010.

	Standard & Poor’s Ratings Services (“S&P”)	**Moody’s Investors Service (“Moody’s”)**	**DBRS Limited (“DBRS”)**
Senior Unsecured			
Long-Term Rating	BBB+	Baa2	A (low)
Outlook	Stable	Stable	Stable
Commercial Paper			
Short-Term Rating	A-1 (low)	P-2	R-1 (low)
Outlook	Stable	Stable	Stable

Credit ratings are intended to provide investors with an independent measure of credit quality of any issue of securities. The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the securities nor do the ratings comment on market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

S&P’s long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality. A rating of BBB+ by S&P is within the fourth highest of ten categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the issuer to meet its financial commitment on the obligation. The addition of a plus (+) or minus (–) modifier after a rating indicates the relative standing within a rating category. S&P’s Canadian commercial paper ratings are on a scale that ranges from A-1 (high) to D, which represents the range from highest to lowest quality. A rating of A-1 (low) is the third highest of eight categories and indicates that the issuer has satisfactory capacity to meet its financial commitments.

Moody’s long-term credit ratings are on a rating scale that ranges from Aaa to C, which represents the range from highest to lowest quality. A rating of Baa2 by Moody’s is within the fourth highest of nine categories and is assigned to obligations subject to moderate credit risk. They are considered medium grade and as such may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the obligation ranks in the higher end of its rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of its rating category. Moody’s short-term credit ratings are on a rating scale that ranges from P-1 to NP, which represents the range from highest to lowest quality. A rating of P-2 is the second highest of four categories and indicates that the issuer has a strong ability to repay short-term debt obligations.

DBRS’ long-term credit ratings are on a rating scale that ranges from AAA to D, which represents the range from highest to lowest quality. A rating of A (low) by DBRS is within the third highest of ten categories and is assigned to obligations considered to be of good credit quality. The capacity for the payment of financial obligations is substantial, but of lesser credit quality than that of higher rated entities. The addition of a high or low modifier after a rating indicates relative standing within the category. DBRS’ commercial paper and short-term debt credit ratings are on a scale ranging from R-1 (high) to D, which represents the range from highest to lowest quality. A rating of R-1 (low) is the third highest of ten categories and indicates that the short-term debt is of good credit quality. The capacity for the payment of short-term financial obligations as they fall due is substantial, but overall strength is not as favourable as higher rating categories. The issuer may be vulnerable to future events, but qualifying negative factors are considered manageable.

Market for Securities

All of the outstanding common shares of Encana are listed and posted for trading on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") under the symbol ECA. The following table outlines the share price trading range and volume of shares traded by month in 2010.

	Toronto Stock Exchange				New York Stock Exchange			
	Share Price Trading Range			Share Volume	Share Price Trading Range			Share Volume
	High	**Low**	**Close**		**High**	**Low**	**Close**	
	(C$ per share)			*(millions)*	*($ per share)*			*(millions)*
2010								
January	36.65	32.41	32.70	44.4	35.63	30.44	30.59	74.9
February	35.53	31.77	34.49	43.0	34.02	29.50	32.78	67.0
March	35.90	30.16	31.60	73.3	34.75	29.31	31.03	88.5
April	34.15	31.03	33.60	57.9	33.63	30.48	33.07	79.1
May	33.98	30.62	33.24	49.9	33.57	28.28	30.85	82.1
June	35.79	32.10	32.24	62.2	35.25	30.29	30.34	83.4
July	35.00	31.06	31.43	41.1	34.04	29.74	30.53	65.0
August	32.45	27.70	29.25	63.0	32.00	26.02	27.49	69.8
September	31.57	28.54	31.09	63.0	30.72	27.58	30.23	68.5
October	31.67	28.05	28.81	51.3	30.98	27.28	28.22	81.0
November	30.41	28.16	28.43	52.7	30.44	27.60	27.70	69.8
December	29.54	28.02	29.09	40.4	29.33	27.73	29.12	54.3

Encana has received approval from the TSX each year to purchase common shares under nine consecutive Normal Course Issuer Bids ("NCIB"). During 2010, the Company purchased about 15.4 million common shares at an average price of approximately $32.42 for total consideration of approximately $499 million. During 2009, the Company did not purchase any of its common shares. During 2008, the Company purchased about 4.8 million common shares for total consideration of approximately $326 million.

Encana is entitled to purchase, for cancellation, up to 36.8 million common shares under the current NCIB, which commenced December 14, 2010 and terminates on December 13, 2011. Purchases may be made through the facilities of the TSX and the NYSE.

Dividends

The declaration of dividends is at the discretion of the Board of Directors and is approved quarterly. From the first quarter of 2008 to the completion of the Split Transaction, Encana paid a quarterly dividend of $0.40 per share (2008 - $1.60 per share annually). In the fourth quarter of 2009, after the Split Transaction, Encana paid a quarterly dividend of $0.20 per share (2009 - $1.40 per share annually). During 2010, Encana paid a quarterly dividend of $0.20 per share (2010 - $0.80 per share annually).

Legal Proceedings

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in Encana's favour, the Company does not currently believe that the outcome of any pending or threatened proceedings related to these or other matters, or the amounts which the Company may be required to pay by reason thereof, would have a material adverse impact on its financial position, results of operations or liquidity.

Risk Factors

If any event arising from the risk factors set forth below occurs, Encana's business, prospects, financial condition, results of operations or cash flows and in some cases its reputation could be materially adversely affected. When assessing the materiality of 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.

A substantial or extended decline in natural gas and liquids prices could have a material adverse effect on Encana.

Encana's financial performance and condition are substantially dependent on the prevailing prices of natural gas and liquids. As Encana is primarily a natural gas company, it is more significantly affected by changes in natural gas prices than changes in liquids prices. Fluctuations in natural gas and liquids prices could have an adverse effect on the Company's operations and financial condition and the value and amount of its reserves. Prices for natural gas and liquids fluctuate in response to changes in the supply and demand for natural gas and crude oil, market uncertainty and a variety of additional factors beyond the Company's control.

Natural gas prices realized by Encana are affected primarily by North American supply and demand, weather conditions and by prices of alternate sources of energy (including refined product, coal, imported liquefied natural gas and renewable energy initiatives). A substantial or extended decline in the price of natural gas could result in a delay or cancellation of existing or future drilling, development or construction programs or curtailment in production at some properties or could result in unutilized long-term transportation and drilling commitments, all of which could have an adverse effect on the Company's revenues, profitability and cash flows.

Crude oil prices are determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the availability of alternate fuel sources and weather conditions. NGLs prices are generally determined with reference to crude oil prices.

Encana conducts an annual assessment of the carrying value of its assets in accordance with Canadian GAAP. If natural gas and liquids prices decline, the carrying value of Encana's assets could be subject to financial downward revisions, and the Company's earnings could be adversely affected.

Encana's ability to operate and complete projects is dependent on factors outside of its control.

The Company's ability to operate, generate sufficient cash flows, and complete projects depends upon numerous factors beyond the Company's control. In addition to commodity prices and continued market demand for its products, these non-controllable factors include general business and market conditions, economic recessions and financial market turmoil, the ability to secure and maintain cost effective financing for its commitments, legislative, environmental and regulatory matters, unexpected cost increases, royalties, taxes, volatility in natural gas and liquids prices, 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.

The tentative recovery from the global recession is creating ongoing fiscal challenges for the world economy. These conditions impact Encana's customers and suppliers and may alter the Company's spending and operating plans. There may be unexpected business impacts from this market uncertainty, including volatile changes in currency exchange rates, inflation, interest rates, and general levels of investing and consuming activity, as well as potential impact on the Company's credit ratings, which could affect its liquidity and ability to obtain financing.

The Company undertakes a variety of projects including exploration and development projects and the construction or expansion of facilities and pipelines. Project delays may delay expected revenues and project cost overruns could make projects uneconomic.

All of Encana's operations are subject to regulation and intervention by governments that can affect or prohibit the drilling, completion and tie-in of wells, production, the construction or expansion of facilities and the operation and abandonment of fields. Contract rights can be cancelled or expropriated. Changes to government regulation could impact the Company's existing and planned projects.

The Company's business is subject to environmental legislation in all jurisdictions in which it operates and any changes in such legislation could negatively affect its results of operations.

All phases of the natural gas and liquids businesses are subject to environmental regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, state and municipal laws and regulations (collectively, "environmental legislation").

Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the use, generation, handling, storage, transportation, treatment and disposal of chemicals, hazardous substances and waste associated with the finding, production, transmission and storage of the Company's products including the hydraulic fracturing of wells, the decommissioning of facilities and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with natural gas and crude oil operations. Environmental legislation also requires that wells, facility sites and other properties associated with Encana's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures, including expenditures for clean up costs and damages arising out of contaminated properties and failure to comply with environmental legislation may result in the imposition of fines and penalties. Although it is not expected that the costs of complying with environmental legislation will have a material adverse effect on Encana's financial condition or results of operations, no assurance can be made that the costs of complying with environmental legislation in the future will not have such an effect.

A number of federal, provincial and state governments have announced intentions to regulate greenhouse gases and other air pollutants. These governments are currently developing the regulatory and policy frameworks to deliver on their announcements. In most cases there are few technical details regarding the implementation and coordination of these plans to regulate emissions. Additionally, it is anticipated that other federal, provincial and state announcements and regulatory frameworks to address emissions will continue to emerge.

Additionally, the U.S. federal and certain U.S. state governments are currently reviewing the regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, these governments are primarily engaged in the collection, review and assessment of technical information regarding the hydraulic fracturing process and have not provided details with respect to any proposed or contemplated changes to the hydraulic fracturing regulatory construct.

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 costs in order to comply with legislation governing emissions and hydraulic fracturing.

If Encana fails to acquire or find additional reserves, the Company's reserves and production will decline materially from their current levels.

Encana's future natural gas and liquids reserves and production, and therefore its cash flows, are highly dependent upon its success in exploiting its current reserves base and acquiring, discovering or developing additional reserves. Without reserves additions through exploration, acquisition or development activities, the Company's reserves and production will decline over time as reserves are depleted. The business of exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient and external sources of capital become limited, Encana's ability to make the necessary capital investments to maintain and expand its natural gas and liquids reserves will be impaired. In addition, there can be no certainty that Encana will be able to find and develop or acquire additional reserves to replace production at acceptable costs.

Encana's reserves data and future net revenue estimates are uncertain.

There are numerous uncertainties inherent in estimating quantities of natural gas and liquids reserves, including many factors beyond the Company's control. The reserves data in this annual information form represents estimates only. In general, estimates of economically recoverable natural gas and liquids reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the assumed effects of regulation by governmental agencies, including with respect to royalty payments, all of which may vary considerably from actual results. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable natural gas and liquids reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Encana's actual production, revenues, taxes and development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

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

Encana's hedging activities could result in realized and unrealized losses.

The nature of the Company's operations results in exposure to fluctuations in commodity prices. The Company monitors its exposure to such fluctuations and, where the Company deems it appropriate, utilizes derivative financial instruments and physical delivery contracts to mitigate the potential impact of declines in natural gas and liquids prices. Under Canadian GAAP, derivative instruments that do not qualify as hedges for accounting purposes, or are not designated as hedges, are fair valued with the resulting changes recognized in current period net earnings. The utilization of derivative financial instruments may therefore introduce significant volatility into the Company's reported net earnings.

The terms of the Company's various hedging agreements may limit the benefit to the Company of commodity price increases. The Company may also suffer financial loss because of hedging arrangements if the Company is unable to produce natural gas or liquids to fulfill delivery obligations, or if counterparties to the Company's hedging agreements fail to fulfill their obligations under the hedging agreements.

Encana's operations are subject to the risk of business interruption and casualty losses.

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 and liquids and the operation of midstream facilities. These risks include blowouts, explosions, fire, gaseous leaks, migration of harmful substances and liquid spills, acts of vandalism and terrorism, any of which could cause personal injury, result in damage to, or destruction of, natural gas and crude oil wells or formations or production facilities and other property, equipment and the environment, as well as interrupt operations. In addition, all of Encana's operations will be subject to all of the risks normally incident to the transportation, processing, storing and marketing of natural gas, liquids, and other related products, drilling and completion of natural gas and crude oil wells, and the operation and development of natural gas and crude oil properties, including encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, equipment failures and other accidents, sour gas releases, uncontrollable flows of natural gas, crude oil or well fluids, adverse weather conditions, pollution and other environmental risks.

The occurrence of a significant event against which Encana is not fully insured could have a material adverse effect on the Company's financial position.

Fluctuations in exchange rates could affect expenses or result in realized and unrealized losses.

Worldwide prices for natural gas and crude oil are set in U.S. dollars. However, many of the Company's expenses outside of the U.S. are denominated in Canadian dollars. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could impact the Company's expenses and have an adverse effect on the Company's financial performance and condition.

In addition, the Company has significant U.S. dollar denominated long-term debt. Fluctuations in the exchange rate between the U.S. dollar and the Canadian dollar could result in realized and unrealized losses on U.S. dollar denominated long-term debt.

Encana does not operate all of its properties and assets.

Other companies operate a portion of the assets in which Encana has ownership interests. Encana will have limited ability to exercise influence over operations of these assets or their associated costs. Encana's dependence on the operator and other working interest owners for these properties and assets, and its limited ability to influence operations and associated costs could materially adversely affect the Company's financial performance. The success and timing of Encana's activities on assets operated by others therefore will depend upon a number of factors that are outside of the Company's control, including timing and amount of capital expenditures, timing and amount of operating and maintenance expenditures, the operator's expertise and financial resources, approval of other participants, selection of technology, and risk management practices.

Encana is exposed to counterparty risk.

Encana is exposed to the risks associated with counterparty performance including credit risk and performance risk. Encana may experience material financial losses in the event of customer payment default for commodity sales and financial derivative transactions. Encana may be impacted by partner defaults with respect to the funding of partner obligations for capital projects. Performance risk can impact Encana's operations by the non-delivery of contracted products or services by counterparties, which could impact project timelines or operational efficiency.

Encana has certain indemnification obligations to Cenovus Energy Inc.

In relation to the Split Transaction, Encana and Cenovus have each agreed to indemnify the other for certain liabilities and obligations associated with, among other things, in the case of Encana's indemnity, the business and assets retained by Encana, and in the case of Cenovus's indemnity, the business and assets transferred to Cenovus. Encana cannot determine whether it will be required to indemnify Cenovus for any substantial obligations. Encana also cannot be assured that, if Cenovus is required to indemnify Encana and its affiliates for any substantial obligations, Cenovus will be able to satisfy such obligations. Any indemnification claim against Encana pursuant to the provisions of the Split Transaction agreements could have a material adverse effect upon Encana.

The Company's foreign operations will expose it to risks from abroad which could negatively affect its results of operations.

Some of Encana's operations and related assets may be located, from time to time, in countries outside North America, some of which may be considered to be politically and economically unstable. Exploration or development activities in such countries may require protracted negotiations with host governments, national oil companies and third parties and are frequently subject to economic and political considerations, such as taxation, nationalization, expropriation, inflation, currency fluctuations, increased regulation and approval requirements, governmental regulation and the risk of actions by terrorist or insurgent groups, any of which could adversely affect the economics of exploration or development projects.

Transfer Agents and Registrars

In Canada:
CIBC Mellon Trust Company
P.O. Box 7010
Adelaide Street Postal Station
Toronto, ON M5C 2W9

In the United States:
BNY Mellon Shareholder Services
480 Washington Blvd.
Jersey City, NJ
07310

In order to respond to Encana shareholder inquiries, the Company's transfer agent has set-up a dedicated answer line. Shareholder inquiries should be directed to the following:

- Shareholders residing in Canada or the United States, please call 1-866-580-7145
- Shareholders residing outside of North America, please call 1-416-643-5990

Shareholders can also send requests via the transfer agent's web site at www.cibcmellon.com/investorinquiry.

Interest of Experts

The Company's independent auditors are PricewaterhouseCoopers LLP, Chartered Accountants, who have issued an independent auditor's report dated February 16, 2011 in respect of the Company's Consolidated Financial Statements as at December 31, 2010 and December 31, 2009 and for each of the years in the three year period ended December 31, 2010 and the Company's internal control over financial reporting as at December 31, 2010. PricewaterhouseCoopers LLP has advised that they are independent with respect to the Company within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and the rules of the SEC.

Information relating to reserves in this annual information form was calculated by GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, each of which is an independent qualified reserves evaluator.

The principals of each of GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd., Netherland, Sewell & Associates, Inc. and DeGolyer and MacNaughton, in each case, as a group own beneficially, directly or indirectly, less than 1 percent of any class of Encana's securities.

Additional Information

Additional information relating to Encana is available on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration, principal holders of Encana's securities, and options to purchase securities, is contained in the Information Circular for Encana's most recent annual meeting of shareholders that involved the election of directors. Additional financial information is contained in Encana's audited Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2010.

The Arrangement Agreement and Separation and Transition Agreement, described under "General Development of the Business – Recent Developments - 2009" are material contracts of Encana and are available on SEDAR.

Note Regarding Forward-Looking Statements

This annual information form contains certain forward-looking statements or information (collectively referred to in this note as “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements are typically identified by words such as “projected”, “anticipate”, “believe”, “expect”, “plan”, “intend” or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking statements in this annual information form include, but are not limited to, statements with respect to: achieving its strategy to be a natural gas producer focused on growing its strong portfolio of natural gas resource plays across North America, drilling and development plans and the timing and location thereof, production and processing capacities, including deep cut processing agreements that will capture more value and enhance returns, and levels and the timing of achieving such capacities and levels, potential completion of a joint venture transaction with PetroChina International Investment Company Limited, 2011 production estimates, the anticipated date of production for the Deep Panuke natural gas project, expansion of gathering and processing plants and other facilities, expected in-service date and additional capacities of Cabin Gas Plant, reserves estimates, including reserves estimates under different price cases, and net present values of future net revenues for reserves using forecast prices and costs and SEC constant prices, the level of expenditures for compliance with environmental legislation and regulations, including estimates of potential costs of carbon, operating costs, site restoration costs including abandonment and reclamation costs, maintaining satisfactory credit ratings, pending litigation, exploration plans, acquisition and divestiture plans and net cash flows.

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 oil and gas prices; assumptions based upon the Company’s current guidance; fluctuations in currency and interest rates; risk that the Company may not conclude potential joint venture arrangements with PetroChina or others 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; 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 and expand reserves; 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. Forward-looking statements with respect to anticipated production, reserves and production growth, including over the next five years, are based upon numerous facts and assumptions which are discussed in further detail in this annual information form, including Encana’s current net drilling location inventory, natural gas price expectations over the next few years, production expectations made in light of advancements in horizontal drilling, multi-stage fracture stimulation and multi-well pad drilling, the current and expected productive characteristics of various existing and emerging resource plays, Encana’s estimates of reserves, expectations for rates of return which may be available at various prices for natural gas and current and expected cost trends. In addition, assumptions relating to such forward-looking statements generally include Encana’s current expectations and projections made in light of, and generally consistent with, its historical experience and its perception of historical trends, including the conversion of resources into reserves and production as well as expectations regarding rates of advancement and innovation, generally consistent with and informed by its past experience, all of which are subject to the risk factors identified elsewhere in this annual information form.

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

Note Regarding Reserves Data and Other Oil and Gas Information

National Instrument 51-101 ("NI 51-101") of the Canadian Securities Administrators imposes oil and gas disclosure standards for Canadian public companies engaged in oil and gas activities. In previous years, 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. As a result of the expiry of that exemption, Encana is providing disclosure which complies with the annual disclosure requirements of NI 51-101 in this annual information form. The Canadian protocol disclosure is contained in Appendix A and under "Narrative Description of the Business". 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. That disclosure is primarily set forth in Appendix D.

See "Reserves and Other Oil and Gas Information" in this annual information form for a description of the primary differences between the disclosure requirements under the Canadian standards and the disclosure requirements under the U.S. standards.

All production information contained in the narrative portions of this annual information form is on a net basis (after royalties), unless otherwise indicated.

Appendix A - Canadian Protocol Disclosure of Reserves Data and Other Oil and Gas Information

In this Appendix, Encana provides disclosure of its reserves and oil and gas information in accordance with the requirements of NI 51-101. See “Note Regarding Reserves Data and Other Oil and Gas Information”. The reserves and other oil and gas information set forth below has an effective date of December 31, 2010 and was prepared as of February 8, 2011.

Since inception, Encana has retained IQREs to evaluate and prepare reports on 100 percent of Encana’s natural gas and liquids reserves annually. For further information regarding the reserves process, see “Reserves and Other Oil and Gas Information” in this annual information form.

The reserves data summarizes the estimated natural gas and liquids reserves of Encana and the net present values of future net revenues for these reserves using forecast prices and costs, as evaluated by Encana’s independent qualified reserves evaluators. The evaluations were prepared in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation (“COGE”) handbook. The reserves definitions used are those contained in the COGE handbook and NI 51-101.

The results of the evaluations are summarized in the tables that follow in this Appendix. All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted), royalties, development costs, production costs and well abandonment costs, but before the consideration of indirect costs such as general and administrative expenses and certain abandonment and reclamation costs. The estimated future net revenue does not necessarily represent the fair market value of Encana’s reserves. There is no assurance that the forecast price and cost assumptions used in preparing the evaluations will be attained and variances could be material. The reserves estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. The actual reserves on Encana’s properties may be greater or less than those calculated.

For further information regarding the reserves process see “Reserves and Other Oil and Gas Information” in this annual information form.

The following product types are referred to in the tables in this Appendix:

- **Coalbed Methane**, which includes coalbed methane commingled with shallow gas sands, related to the Clearwater Business Unit in the Canadian Division.

- **Shale Gas**, which includes Horn River shale gas in the Canadian Division and Barnett and Haynesville shale gas in the USA Division.

- **Other**, which includes natural gas other than coalbed methane and shale gas. Reserves and production include the following key resource plays: Greater Sierra (excluding Horn River shale), Cutbank Ridge and Bighorn in the Canadian Division; and Jonah, Piceance, and East Texas in the USA Division.

- **Liquids**, which includes natural gas liquids plus light and medium oil, of which light and medium oil is not material.

Reserves Data (Canadian Protocol)

Summary of Oil and Gas Reserves (1)
(Forecast Prices and Costs; Before and After Royalties)

As at December 31, 2010

Canadian Division

	Natural Gas *(Bcf)*								Liquids *(MMbbls)*		Total *(Bcfe)*	
	Coalbed Methane		Shale Gas		Other		Total					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved												
Developed producing	915	968	124	117	2,065	1,822	3,104	2,907	24.1	24.2	3,249	3,053
Developed non-producing	207	203	-	-	117	105	324	308	1.6	1.2	333	316
Undeveloped	688	680	387	337	2,252	2,066	3,327	3,083	36.2	29.4	3,544	3,258
Total Proved	1,810	1,851	511	454	4,434	3,993	6,755	6,298	61.9	54.8	7,126	6,627
Probable	463	480	502	404	1,695	1,526	2,660	2,410	23.1	20.0	2,799	2,529
Total Proved Plus Probable	**2,273**	**2,331**	**1,013**	**858**	**6,129**	**5,519**	**9,415**	**8,708**	**85.0**	**74.8**	**9,925**	**9,156**

USA Division

	Natural Gas *(Bcf)*								Liquids *(MMbbls)*		Total *(Bcfe)*	
	Coalbed Methane		Shale Gas		Other		Total					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved												
Developed producing	-	-	966	747	3,338	2,750	4,304	3,497	24.8	20.1	4,453	3,618
Developed non-producing	-	-	58	46	319	259	377	305	5.0	4.1	407	329
Undeveloped	-	-	2,421	1,892	2,197	1,783	4,618	3,675	17.6	14.3	4,724	3,761
Total Proved	-	-	3,445	2,685	5,854	4,792	9,299	7,477	47.4	38.5	9,584	7,708
Probable	-	-	3,528	2,806	3,765	3,172	7,293	5,978	29.3	24.1	7,468	6,123
Total Proved Plus Probable	**-**	**-**	**6,973**	**5,491**	**9,619**	**7,964**	**16,592**	**13,455**	**76.7**	**62.6**	**17,052**	**13,831**

Total Encana

	Natural Gas *(Bcf)*								Liquids *(MMbbls)*		Total *(Bcfe)*	
	Coalbed Methane		Shale Gas		Other		Total					
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved												
Developed producing	915	968	1,090	864	5,403	4,572	7,408	6,404	48.9	44.3	7,702	6,671
Developed non-producing	207	203	58	46	436	364	701	613	6.6	5.3	740	645
Undeveloped	688	680	2,808	2,229	4,449	3,849	7,945	6,758	53.8	43.7	8,268	7,019
Total Proved	1,810	1,851	3,956	3,139	10,288	8,785	16,054	13,775	109.3	93.3	16,710	14,335
Probable	463	480	4,030	3,210	5,460	4,698	9,953	8,388	52.4	44.1	10,267	8,652
Total Proved Plus Probable	**2,273**	**2,331**	**7,986**	**6,349**	**15,748**	**13,483**	**26,007**	**22,163**	**161.7**	**137.4**	**26,977**	**22,987**

Notes:

(1) Definitions

a) "Gross" reserves are Encana's working interest share before the deduction of estimated royalty obligations and excluding any royalty interests.

b) "Net" reserves are Encana's working interest share after deduction of estimated royalty obligations and including Encana's royalty interests.

c) "Reserves" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable.

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

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

f) "Developed producing" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

g) "Developed non-producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

h) "Undeveloped" reserves are those reserves that are expected to be recovered from known accumulations where a significant expenditure (i.e., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (proved, probable) to which they are assigned.

Summary of Net Present Value of Future Net Revenue
(Forecast Prices and Costs; Before Tax)

As at December 31, 2010

Canadian Division

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	11,713	8,686	6,925	5,790	5,001
Developed non-producing	1,015	687	504	389	312
Undeveloped	8,703	5,076	3,159	2,019	1,287
Total Proved	21,431	14,449	10,588	8,198	6,600
Probable	9,364	4,865	2,924	1,922	1,339
Total Proved Plus Probable	**30,795**	**19,314**	**13,512**	**10,120**	**7,939**

USA Division

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	13,793	9,998	7,828	6,457	5,522
Developed non-producing	1,417	1,065	846	699	595
Undeveloped	10,175	5,960	3,699	2,360	1,509
Total Proved	25,385	17,023	12,373	9,516	7,626
Probable	18,168	9,447	5,328	3,147	1,895
Total Proved Plus Probable	**43,553**	**26,470**	**17,701**	**12,663**	**9,521**

Total Encana

	Future Net Revenue Before Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	25,506	18,684	14,753	12,247	10,523
Developed non-producing	2,432	1,752	1,350	1,088	907
Undeveloped	18,878	11,036	6,858	4,379	2,796
Total Proved	46,816	31,472	22,961	17,714	14,226
Probable	27,532	14,312	8,252	5,069	3,234
Total Proved Plus Probable	**74,348**	**45,784**	**31,213**	**22,783**	**17,460**

Summary of Net Present Value of Future Net Revenue
(Forecast Prices and Costs; After Tax)

As at December 31, 2010

Canadian Division

	Future Net Revenue After Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	10,331	7,831	6,352	5,383	4,698
Developed non-producing	759	511	372	286	229
Undeveloped	6,492	3,652	2,143	1,245	670
Total Proved	17,582	11,994	8,867	6,914	5,597
Probable	6,994	3,584	2,111	1,352	913
Total Proved Plus Probable	**24,576**	**15,578**	**10,978**	**8,266**	**6,510**

USA Division

	Future Net Revenue After Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	11,001	7,987	6,281	5,204	4,469
Developed non-producing	905	688	551	459	393
Undeveloped	6,494	3,806	2,384	1,547	1,015
Total Proved	18,400	12,481	9,216	7,210	5,877
Probable	11,586	5,986	3,372	1,993	1,204
Total Proved Plus Probable	**29,986**	**18,467**	**12,588**	**9,203**	**7,081**

Total Encana

	Future Net Revenue After Future Income Tax and Discounted at				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed producing	21,332	15,818	12,633	10,587	9,167
Developed non-producing	1,664	1,199	923	745	622
Undeveloped	12,986	7,458	4,527	2,792	1,685
Total Proved	35,982	24,475	18,083	14,124	11,474
Probable	18,580	9,570	5,483	3,345	2,117
Total Proved Plus Probable	**54,562**	**34,045**	**23,566**	**17,469**	**13,591**

Additional Information Concerning Future Net Revenue
(Forecast Prices and Costs; Undiscounted)

As at December 31, 2010

($ millions)	Canadian Division		USA Division		Total	
	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Revenues	39,449	55,568	55,729	99,594	95,178	155,162
Royalties, production and mineral taxes	3,382	5,152	14,100	23,891	17,482	29,043
Operating costs	8,859	11,757	7,905	13,030	16,764	24,787
Development costs	5,154	7,200	7,772	18,345	12,926	25,545
Abandonment costs	623	664	567	775	1,190	1,439
Future net revenue, before income taxes	21,431	30,795	25,385	43,553	46,816	74,348
Income tax	3,849	6,219	6,985	13,567	10,834	19,786
Future net revenue, after income taxes	**17,582**	**24,576**	**18,400**	**29,986**	**35,982**	**54,562**

Future Net Revenue by Production Group
(Forecast Prices and Costs)

As at December 31, 2010

	Natural Gas				Total	
	Coalbed Methane and Shale Gas (1)		Associated and Non-associated Gas (2)			
(discounted at 10%/yr, $ millions)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
Future Net Revenue Before Income Taxes	6,523	10,030	16,437	21,183	22,960	31,213
Unit Value *($/Mcfe)* (3)	1.30	1.15	1.78	1.51	1.60	1.36

Notes:

(1) Includes by-products.
(2) Including by-products as well as future net revenue from oil (including solution gas and other by-products) which are not material.
(3) Unit values are based on net reserves volumes.

Pricing Assumptions (Forecast Prices)

The following pricing and exchange rate assumptions were utilized by the independent qualified reserves evaluators in estimating Encana's reserves data using forecast prices and costs. These assumptions were provided by Encana and are the same pricing assumptions used for the business case included in "Net Proved Reserves (U.S. Protocol)" in Appendix D in this annual information form.

	Natural Gas		**Crude Oil and Natural Gas Liquids**		**Foreign Exchange Rate** (2)	**Inflation Rate**(3)
Year	Henry Hub *($/MMBtu)*	AECO *(C$/MMBtu)*	WTI *($/bbl)*	Edmonton (1) *(C$/bbl)*	*US$/C$*	*%/yr*
2010 (4,5)	4.39	4.12	79.55	75.79	0.9710	
2011	4.73	4.35	79.53	81.93	0.9342	-
2012	5.33	4.94	82.65	85.88	0.9275	-
2013	5.64	5.31	84.21	88.09	0.9219	-
2014	5.82	5.55	85.33	89.83	0.9166	-
2015	6.01	5.78	86.68	91.61	0.9134	-
Thereafter:	6.18 – 6.63	5.97 – 6.48	83.72	88.37	0.9134	-

Notes:

(1) Mixed Sweet Blend at Edmonton.
(2) The exchange rates used to generate the Canadian benchmark reference prices in this table.
(3) Default cost inflation rate. Abnormal inflationary situations in certain regions are handled individually by directly increasing the cost estimates for the years affected.
(4) Average prices for 2010.
(5) Encana's weighted average prices for 2010 excluding the impact of realized hedging were $4.45/Mcf for natural gas and $66.57/bbl for liquids.

Reconciliation of Changes in Reserves (Before Royalties)

The following tables provide a reconciliation of Encana's gross reserves of natural gas, crude oil and NGLs for the year ended December 31, 2010, presented using forecast prices and costs.

Proved Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Division

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	1,539	176	4,396	6,111	41.6	6,361
Extensions and improved recovery	324	266	527	1,117	21.1	1,245
Technical revisions	25	63	(69)	19	6.7	59
Discoveries	-	17	43	60	0.6	63
Acquisitions	126	-	6	132	0.5	135
Dispositions	(2)	-	(88)	(90)	(2.8)	(107)
Economic factors	(55)	-	(35)	(90)	(0.1)	(91)
Production	(147)	(11)	(346)	(504)	(5.7)	(539)
December 31, 2010	**1,810**	**511**	**4,434**	**6,755**	**61.9**	**7,126**

USA Division

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	-	1,878	6,294	8,172	55.7	8,506
Extensions and improved recovery	-	904	375	1,279	2.4	1,293
Technical revisions	-	905	97	1,002	0.5	1,005
Discoveries	-	43	-	43	-	43
Acquisitions	-	-	92	92	0.6	95
Dispositions	-	(82)	(373)	(455)	(7.3)	(498)
Economic factors	-	(11)	32	21	(0.1)	21
Production	-	(192)	(663)	(855)	(4.4)	(881)
December 31, 2010	**-**	**3,445**	**5,854**	**9,299**	**47.4**	**9,584**

Total Encana

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	1,539	2,054	10,690	14,283	97.3	14,867
Extensions and improved recovery	324	1,170	902	2,396	23.5	2,538
Technical revisions	25	968	28	1,021	7.2	1,064
Discoveries	-	60	43	103	0.6	106
Acquisitions	126	-	98	224	1.1	230
Dispositions	(2)	(82)	(461)	(545)	(10.1)	(605)
Economic factors	(55)	(11)	(3)	(69)	(0.2)	(70)
Production	(147)	(203)	(1,009)	(1,359)	(10.1)	(1,420)
December 31, 2010	**1,810**	**3,956**	**10,288**	**16,054**	**109.3**	**16,710**

Probable Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Division

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	359	144	1,775	2,278	16.6	2,377
Extensions and improved recovery	177	317	131	625	8.2	673
Technical revisions	(132)	35	(171)	(268)	(0.6)	(271)
Discoveries	-	5	(8)	(3)	(0.1)	(3)
Acquisitions	21	-	3	24	0.1	25
Dispositions	(1)	-	(53)	(54)	(1.2)	(61)
Economic factors	39	1	18	58	0.1	59
Production	-	-	-	-	-	-
December 31, 2010	**463**	**502**	**1,695**	**2,660**	**23.1**	**2,799**

USA Division

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	-	2,142	3,210	5,352	35.6	5,566
Extensions and improved recovery	-	1,777	862	2,639	5.2	2,671
Technical revisions	-	(362)	(202)	(564)	(3.1)	(583)
Discoveries	-	118	-	118	-	118
Acquisitions	-	-	65	65	0.8	70
Dispositions	-	(150)	(168)	(318)	(9.3)	(375)
Economic factors	-	3	(2)	1	0.1	1
Production	-	-	-	-	-	-
December 31, 2010	**-**	**3,528**	**3,765**	**7,293**	**29.3**	**7,468**

Total Encana

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	359	2,286	4,985	7,630	52.2	7,943
Extensions and improved recovery	177	2,094	993	3,264	13.4	3,344
Technical revisions	(132)	(327)	(373)	(832)	(3.7)	(854)
Discoveries	-	123	(8)	115	(0.1)	115
Acquisitions	21	-	68	89	0.9	95
Dispositions	(1)	(150)	(221)	(372)	(10.5)	(436)
Economic factors	39	4	16	59	0.2	60
Production	-	-	-	-	-	-
December 31, 2010	**463**	**4,030**	**5,460**	**9,953**	**52.4**	**10,267**

Proved Plus Probable Reserves
(Forecast Prices and Costs; Before Royalties)

Canadian Division

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	1,898	320	6,171	8,389	58.2	8,738
Extensions and improved recovery	501	583	658	1,742	29.3	1,918
Technical revisions	(107)	98	(240)	(249)	6.1	(212)
Discoveries	-	22	35	57	0.5	60
Acquisitions	147	-	9	156	0.6	160
Dispositions	(3)	-	(141)	(144)	(4.0)	(168)
Economic factors	(16)	1	(17)	(32)	-	(32)
Production	(147)	(11)	(346)	(504)	(5.7)	(539)
December 31, 2010	**2,273**	**1,013**	**6,129**	**9,415**	**85.0**	**9,925**

USA Division

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	-	4,020	9,504	13,524	91.3	14,072
Extensions and improved recovery	-	2,681	1,237	3,918	7.6	3,964
Technical revisions	-	543	(105)	438	(2.6)	422
Discoveries	-	161	-	161	-	161
Acquisitions	-	-	157	157	1.4	165
Dispositions	-	(232)	(541)	(773)	(16.6)	(873)
Economic factors	-	(8)	30	22	-	22
Production	-	(192)	(663)	(855)	(4.4)	(881)
December 31, 2010	**-**	**6,973**	**9,619**	**16,592**	**76.7**	**17,052**

Total Encana

	Natural Gas *(Bcf)*				Liquids *(MMbbls)*	Total *(Bcfe)*
	Coalbed Methane	Shale Gas	Other	Total		
December 31, 2009	1,898	4,340	15,675	21,913	149.5	22,810
Extensions and improved recovery	501	3,264	1,895	5,660	36.9	5,882
Technical revisions	(107)	641	(345)	189	3.5	210
Discoveries	-	183	35	218	0.5	221
Acquisitions	147	-	166	313	2.0	325
Dispositions	(3)	(232)	(682)	(917)	(20.6)	(1,041)
Economic factors	(16)	(7)	13	(10)	-	(10)
Production	(147)	(203)	(1,009)	(1,359)	(10.1)	(1,420)
December 31, 2010	**2,273**	**7,986**	**15,748**	**26,007**	**161.7**	**26,977**

Undeveloped Reserves, Significant Factors or Uncertainties and Future Development Costs

Undeveloped Reserves

Proved and probable undeveloped reserves are attributed where warranted on the basis of technical merit, commercial considerations and development plans. These development opportunities are being pursued at a pace dependent on capital availability and allocation. As a result, development is scheduled beyond the next two years. All of the proved and probable undeveloped reserves at December 31, 2010 are scheduled for development within the next five and eight years respectively in Canada and the United States.

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the three most recent financial years and in the aggregate before that time, along with the total proved undeveloped reserves of the Company at the end of each such year.

Proved Undeveloped Reserves

	Natural Gas *(Bcf)*								**Liquids** *(MMbbls)*		**Total** *(Bcfe)*	
	Coalbed Methane		**Shale Gas**		**Other**		**Total**					
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	At Year End
Prior	1,111	1,111	378	378	4,214	4,214	5,703	5,703	37.0	37.0	5,925	5,925
2008	15	923	85	368	1,528	4,611	1,628	5,902	15.0	42.1	1,718	6,154
2009	-	559	832	1,217	1,222	4,500	2,054	6,276	11.6	38.1	2,124	6,504
2010	442	688	1,161	2,808	1,105	4,449	2,708	7,945	18.7	53.8	2,820	8,268

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the three most recent financial years and in the aggregate before that time, along with the total probable undeveloped reserves of the Company at the end of each such year.

Probable Undeveloped Reserves

	Natural Gas *(Bcf)*								**Liquids** *(MMbbls)*		**Total** *(Bcfe)*	
	Coalbed Methane		**Shale Gas**		**Other**		**Total**					
	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	Total at Year End	First Attributed	At Year End
Prior	191	191	444	444	5,332	5,332	5,967	5,967	38.4	38.4	6,198	6,198
2008	-	166	337	593	1,355	4,671	1,692	5,430	24.0	46.9	1,836	5,711
2009	-	182	1,771	2,264	1,421	4,419	3,192	6,865	10.1	41.8	3,253	7,116
2010	67	290	2,289	3,889	1,459	4,901	3,815	9,080	12.9	42.6	3,893	9,336

Significant Factors or Uncertainties

The development schedule of our undeveloped reserves is based on forecast price assumptions for the determination of economic projects. The actual prices that occur may be significantly lower or higher resulting in some projects being delayed or accelerated, as the case may be. For further information see “Risk Factors” in this annual information form.

Our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control.

Future Development Costs

The table below summarizes Encana’s development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves, using undiscounted forecast prices and costs.

	Canadian Division		**USA Division**		**Total Encana**	
($ millions)	Proved	Proved Plus Probable	Proved	Proved Plus Probable	Proved	Proved Plus Probable
2011	1,496	1,605	1,468	2,165	2,964	3,770
2012	1,440	1,753	1,587	2,536	3,027	4,289
2013	1,278	1,693	1,583	2,599	2,861	4,292
2014	731	1,173	1,736	2,810	2,467	3,983
2015	186	632	1,051	2,743	1,237	3,375
Remainder	23	344	347	5,492	370	5,836
Total	**5,154**	**7,200**	**7,772**	**18,345**	**12,926**	**25,545**

Future development costs are associated with reserves as evaluated by the IQREs and do not necessarily represent Encana’s exploration and development budget. Encana expects to fund its future development costs with future cash flow, available cash balances, divestitures, joint ventures, or a combination of these.

Abandonment, Tax and Costs Incurred

Abandonment and Reclamation Costs

Encana expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed. The asset retirement obligation (“ARO”) is estimated by discounting the expected future cash flows of the settlement. The discounted cash flows are based on estimates of reserve lives, retirement costs, discount rates and future inflation rates. In 2010, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were not material. Based on Encana’s current estimate, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred is estimated at approximately $4.7 billion ($398 million discounted at 10 percent). As at December 31, 2010, Encana has recorded an asset retirement obligation of $820 million. These estimates include the abandonment of 21,640 net wells. Over the next three years, Encana’s net well abandonment and reclamation cost is expected to total $125 million ($109 million discounted at 10 percent).

For the purposes of the reserves evaluations prepared by the IQREs, costs deducted as abandonment costs in estimating future net revenue do not include reclamation costs or abandonment costs of facilities and wells without reserves.

Tax Horizon

Encana was not cash taxable for 2010. Based on the long range plan approved by the Board of Directors in June 2010, the Company estimates it will not be cash taxable for the next two to three years. The long range plan is reviewed annually, and as a result, the cash tax forecast may be revised for factors including the outlook for natural gas commodity prices and the expectations for capital investment by the Company.

2010 Costs Incurred

($ millions)	**Canadian Division**	**USA Division**	**Total**
Acquisitions			
Unproved	395	97	492
Proved	197	44	241
Total acquisitions	592	141	733
Exploration costs	58	198	256
Development costs	2,153	2,301	4,454
Total costs incurred	**2,803**	**2,640**	**5,443**

Location of Oil and Gas Wells

The following table summarizes Encana's interests in natural gas or oil wells which are producing, or the Company considers capable of production, as at December 31, 2010.

For additional information on the location of Encana's properties, plants, facilities and installations, refer to "Narrative Description of the Business" in this annual information form.

	Producing Gas		Producing Oil		Total Producing [1,2]		Non-Producing Gas		Non-Producing Oil		Total Non- Producing [3]	
(number of wells)	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	11,576	10,444	247	146	11,823	10,590	1,790	1,491	245	144	2,035	1,635
British Columbia	1,749	1,634	3	3	1,752	1,637	336	288	6	3	342	291
Total Canadian Division	**13,325**	**12,078**	**250**	**149**	**13,575**	**12,227**	**2,126**	**1,779**	**251**	**147**	**2,377**	**1,926**
Colorado	4,309	3,666	6	1	4,315	3,667	299	272	-	-	299	272
Texas	1,411	1,034	6	3	1,417	1,037	37	28	-	-	37	28
Wyoming	1,752	1,449	1	-	1,753	1,449	107	89	-	-	107	89
Utah	1	1	-	-	1	1	-	-	-	-	-	-
Louisiana	250	132	-	-	250	132	-	-	-	-	-	-
Kansas	1	1	-	-	1	1	-	-	-	-	-	-
Michigan	-	-	-	-	-	-	1	1	-	-	1	1
Montana	-	-	-	-	-	-	1	1	-	-	1	1
Total USA Division	**7,724**	**6,283**	**13**	**4**	**7,737**	**6,287**	**445**	**391**	**-**	**-**	**445**	**391**
Total Encana	**21,049**	**18,361**	**263**	**153**	**21,312**	**18,514**	**2,571**	**2,170**	**251**	**147**	**2,822**	**2,317**

Notes:

(1) Encana has varying royalty interests in approximately 8,600 natural gas wells and approximately 5,450 crude oil wells which are producing or capable of producing.

(2) Includes wells containing multiple completions as follows; approximately 11,715 gross natural gas wells (10,867 net wells) and approximately 162 gross crude oil (120 net wells).

(3) "Non-producing" wells refer to wells that are capable of producing oil or natural gas, but which are not producing due the timing of well completions and/or waiting to be tied in which is anticipated to occur in 2012, or are wells that are temporarily shut-in due to market conditions, but not yet abandoned. All non-producing oil and natural gas wells considered capable of producing are located near existing infrastructure and/or within economic distance of transportation.

Landholdings with No Attributed Reserves

The following table summarizes the gross and net acres with no attributed reserves in which Encana has an interest at December 31, 2010 and the net acres with no attributed reserves for which we expect our rights to explore, develop and exploit to expire during 2011.

(thousands of acres)	**Gross Acres (1)**	**Net Acres (1)**	**Net Acres Expiring Within One Year**
Canada			
Alberta	4,556	3,931	49
British Columbia	2,445	1,953	139
Newfoundland and Labrador	35	2	-
Nova Scotia	20	9	-
Northwest Territories	45	12	-
Total Canada	**7,101**	**5,907**	**188**
United States			
Colorado	801	757	43
Texas	581	452	177
Wyoming	282	236	26
Louisiana	368	266	126
Michigan	424	424	-
Other	123	99	26
Total United States	**2,579**	**2,234**	**398**
International			
Greenland	-	-	-
Azerbaijan	346	17	-
Australia	104	40	-
Total International	**450**	**57**	**-**
Total	**10,130**	**8,198**	**586**

Note:

(1) Properties with different formations under the same surface area and subject to separate leases have been calculated on an aerial basis, as such gross and net acreage have only been counted once.

Exploration and Development Activities

The following tables summarize Encana's gross participation and net interest in wells drilled for the periods indicated. See "Narrative Description of the Business" in this annual information form, for discussion on Encana's most important current and likely exploration and development activities.

Exploration Wells Drilled [1,2]

	Gas		Oil		Service		Dry and Abandoned		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2010 [3]											
Canadian Division	22	15	-	-	1	1	-	-	31	54	16
USA Division	34	15	-	-	-	-	2	2	-	36	17
Total	**56**	**30**	**-**	**-**	**1**	**1**	**2**	**2**	**31**	**90**	**33**

Notes:

(1) "Gross" wells are the total number of wells in which Encana has an interest.
(2) "Net" wells are the number of wells obtained by aggregating Encana's working interest in each of its gross wells.
(3) At December 31, 2010, Encana was in the process of drilling the following exploratory and development wells: approximately 21 gross wells (21 net wells) in Canada and approximately 75 gross wells (49 net wells) in the United States.

Development Wells Drilled [1,2]

	Gas		Oil		Service		Dry and Abandoned		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2010 [3]											
Canadian Division	1,270	1,190	1	1	4	3	-	-	203	1,478	1,194
USA Division	748	428	-	-	1	1	4	3	144	897	432
Total	**2,018**	**1,618**	**1**	**1**	**5**	**4**	**4**	**3**	**347**	**2,375**	**1,626**

Notes:

(1) "Gross" wells are the total number of wells in which Encana has an interest.
(2) "Net" wells are the number of wells obtained by aggregating Encana's working interest in each of its gross wells.
(3) At December 31, 2010, Encana was in the process of drilling the following exploratory and development wells: approximately 21 gross wells (21 net wells) in Canada and approximately 75 gross wells (49 net wells) in the United States.

Production Volumes (Before Royalties)

2011 Production Estimates (Before Royalties)

The following table summarizes the total volume of production estimated for the year ended December 31, 2011, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "Reserves Data (Canadian Protocol)" in this Appendix above.

Canadian Division

	Natural Gas *(Bcf)*				**Liquids** *(MMbbls)*	**Total** *(Bcfe)*
(annual)	Coalbed Methane	Shale Gas	Other	Total		
Proved	145	31	376	552	4.4	578
Probable	5	3	15	23	0.3	25
Total Proved Plus Probable	**150**	**34**	**391**	**575**	**4.7**	**603**

USA Division

	Natural Gas *(Bcf)*				**Liquids** *(MMbbls)*	**Total** *(Bcfe)*
(annual)	Coalbed Methane	Shale Gas	Other	Total		
Proved	0.0	289	557	846	3.6	869
Probable	0.0	81	30	111	0.1	111
Total Proved Plus Probable	**0.0**	**370**	**587**	**957**	**3.7**	**980**

Total Encana

	Natural Gas *(Bcf)*				**Liquids** *(MMbbls)*	**Total** *(Bcfe)*
(annual)	Coalbed Methane	Shale Gas	Other	Total		
Proved	145	320	933	1,398	8.0	1,447
Probable	5	84	45	134	0.4	136
Total Proved Plus Probable	**150**	**404**	**978**	**1,532**	**8.4**	**1,583**

2010 Production Volumes by Country (Before Royalties)

(average daily)	2010 Annual	Q4	Q3	Q2	Q1
Coalbed Methane *(MMcf/d)*					
Canadian Division	402	428	386	393	402
USA Division	-	-	-	-	-
	402	428	386	393	402
Shale Gas *(MMcf/d)*					
Canadian Division	30	49	34	26	11
USA Division	541	665	569	499	430
	571	714	603	525	441
Other *(MMcf/d)*					
Canadian Division	949	953	1,003	967	871
USA Division	1,801	1,638	1,680	1,861	2,028
	2,750	2,591	2,683	2,828	2,899
Total Produced Gas *(MMcf/d)*					
Canadian Division	1,381	1,430	1,423	1,386	1,284
USA Division	2,342	2,303	2,249	2,360	2,458
	3,723	3,733	3,672	3,746	3,742
Liquids *(bbls/d)*					
Canadian Division	15,743	14,019	16,844	16,229	15,889
USA Division	11,928	11,342	11,156	12,709	12,526
	27,671	25,361	28,000	28,938	28,415
Total Encana *(MMcfe/d)*					
Canadian Division	1,475	1,514	1,524	1,484	1,379
USA Division	2,414	2,371	2,316	2,436	2,533
	3,889	3,885	3,840	3,920	3,912
Total Encana *(BOE/d)*					
Canadian Division	245,910	252,352	254,011	247,229	229,889
USA Division	402,261	395,175	385,989	406,042	422,193
	648,171	**647,527**	**640,000**	**653,271**	**652,082**

Per-Unit Results (Before Royalties)

The following tables summarize the net per-unit results for Encana for the periods indicated, which exclude the impact of realized hedging.

Netbacks by Current Division & Country (Before Royalties)

	2010				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Coalbed Methane *($/Mcf)*					
Canadian Division and Total Encana					
Price, before royalties	3.98	3.58	3.60	3.77	5.00
Royalties	0.05	0.06	0.04	0.04	0.07
Production and mineral taxes	0.04	(0.01)	0.07	0.08	0.03
Transportation	0.15	0.12	0.16	0.17	0.18
Operating	1.18	1.28	1.11	1.17	1.15
	2.56	**2.13**	**2.22**	**2.31**	**3.57**
Shale Gas *($/Mcf)*					
Canadian Division					
Price, before royalties	3.38	3.42	3.04	3.05	5.04
Royalties	0.09	0.06	0.06	0.17	0.11
Production and mineral taxes	-	-	-	-	-
Transportation	0.61	0.66	0.49	0.66	0.62
Operating	0.76	0.48	0.71	0.46	2.87
	1.92	2.22	1.78	1.76	1.44
USA Division					
Price, before royalties	4.60	3.92	4.74	4.50	5.60
Royalties	0.96	0.82	0.99	0.97	1.16
Production and mineral taxes	0.03	0.06	-	0.03	0.06
Transportation	0.72	0.73	0.71	0.59	0.86
Operating	0.64	0.60	0.61	0.73	0.67
	2.25	1.71	2.43	2.18	2.85
Total Encana					
Price, before royalties	4.53	3.88	4.64	4.43	5.58
Royalties	0.92	0.77	0.93	0.93	1.14
Production and mineral taxes	0.03	0.05	-	0.03	0.05
Transportation	0.71	0.72	0.70	0.60	0.86
Operating	0.65	0.59	0.61	0.72	0.72
	2.22	**1.75**	**2.40**	**2.15**	**2.81**
Other *($/Mcf)*					
Canadian Division					
Price, before royalties	4.17	3.81	3.74	3.98	5.28
Royalties	0.23	0.10	0.09	0.21	0.57
Production and mineral taxes	-	-	-	-	-
Transportation	0.47	0.50	0.47	0.44	0.46
Operating	1.00	1.17	0.88	0.89	1.06
	2.47	2.04	2.30	2.44	3.19

Netbacks by Current Division & Country (Before Royalties)

	2010				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Other *($/Mcf)*					
USA Division					
Price, before royalties	4.68	4.08	4.45	4.29	5.74
Royalties	0.88	0.76	0.85	0.76	1.14
Production and mineral taxes	0.27	0.24	0.26	0.24	0.33
Transportation	0.79	0.80	0.83	0.82	0.73
Operating	0.41	0.42	0.46	0.43	0.32
	2.33	1.86	2.05	2.04	3.22
Total Encana					
Price, before royalties	4.51	3.98	4.18	4.19	5.60
Royalties	0.66	0.52	0.56	0.57	0.96
Production and mineral taxes	0.18	0.15	0.16	0.16	0.23
Transportation	0.68	0.69	0.70	0.69	0.64
Operating	0.61	0.70	0.62	0.59	0.55
	2.38	**1.92**	**2.14**	**2.18**	**3.22**
Total Produced Gas *($/Mcf)*					
Canadian Division					
Price, before royalties	4.10	3.73	3.69	3.90	5.19
Royalties	0.18	0.09	0.08	0.16	0.42
Production and mineral taxes	0.01	-	0.02	0.02	0.01
Transportation	0.38	0.39	0.38	0.37	0.38
Operating	1.05	1.18	0.94	0.96	1.10
	2.48	2.07	2.27	2.39	3.28
USA Division					
Price, before royalties	4.66	4.03	4.52	4.34	5.72
Royalties	0.90	0.78	0.88	0.80	1.14
Production and mineral taxes	0.22	0.19	0.20	0.20	0.28
Transportation	0.77	0.78	0.80	0.77	0.75
Operating	0.46	0.47	0.50	0.50	0.38
	2.31	1.81	2.14	2.07	3.17
Total Encana					
Price, before royalties	4.45	3.92	4.20	4.18	5.54
Royalties	0.63	0.51	0.57	0.56	0.89
Production and mineral taxes	0.14	0.12	0.13	0.13	0.19
Transportation	0.63	0.63	0.64	0.62	0.62
Operating	0.68	0.74	0.67	0.67	0.63
	2.37	**1.92**	**2.19**	**2.20**	**3.21**
Liquids *($/bbl)*					
Canadian Division					
Price, before royalties	64.35	68.87	58.84	63.21	67.43
Royalties	10.24	12.93	8.50	10.28	9.65
Production and mineral taxes	0.37	0.41	0.32	0.44	0.30
Transportation	0.68	0.56	0.79	0.91	0.45
Operating	2.71	3.25	1.92	1.84	3.98
	50.35	51.72	47.31	49.74	53.05
USA Division					
Price, before royalties	69.50	74.39	66.38	70.14	67.15
Royalties	13.46	14.93	11.99	13.95	12.94
Production and mineral taxes	5.40	6.03	5.26	5.31	5.04
Transportation	-	-	-	-	-
	50.64	53.43	49.13	50.88	49.17

Netbacks by Current Division & Country (Before Royalties)

	2010				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Liquids *($/bbl)*					
Total Encana					
Price, before royalties	66.57	71.34	61.84	66.25	67.31
Royalties	11.63	13.82	9.89	11.89	11.10
Production and mineral taxes	2.54	2.92	2.29	2.58	2.39
Transportation	0.39	0.31	0.47	0.51	0.25
Operating	1.54	1.80	1.16	1.03	2.23
	50.47	**52.49**	**48.03**	**50.24**	**51.34**
Total Netback *($/Mcfe)*					
Canadian Division					
Price, before royalties	4.52	4.16	4.09	4.33	5.60
Royalties	0.28	0.20	0.17	0.26	0.50
Production and mineral taxes	0.02	-	0.02	0.03	0.01
Transportation	0.36	0.37	0.37	0.35	0.36
Operating	1.01	1.15	0.90	0.92	1.07
	2.85	2.44	2.63	2.77	3.66
USA Division					
Price, before royalties	4.87	4.27	4.71	4.57	5.88
Royalties	0.94	0.83	0.91	0.85	1.17
Production and mineral taxes	0.24	0.21	0.22	0.22	0.30
Transportation	0.75	0.76	0.78	0.75	0.73
Operating	0.45	0.46	0.48	0.48	0.37
	2.49	2.01	2.32	2.27	3.31
Total Encana					
Price, before royalties	4.74	4.23	4.46	4.48	5.78
Royalties	0.69	0.58	0.62	0.63	0.93
Production and mineral taxes	0.15	0.13	0.14	0.15	0.20
Transportation	0.60	0.61	0.61	0.60	0.59
Operating	0.66	0.73	0.65	0.65	0.62
	2.64	**2.18**	**2.44**	**2.45**	**3.44**

Impact of Realized Hedging on Encana's Netbacks

	2010				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Natural Gas *($/Mcf)*	0.87	0.95	0.94	1.09	0.48
Liquids *($/bbl)*	(0.50)	(1.73)	(0.30)	0.26	(0.34)
Total *($/Mcfe)*	0.83	0.90	0.90	1.04	0.46

Appendix B - Report on Reserves Data by Independent Qualified Reserves Evaluators (Canadian Protocol)

To the Board of Directors of Encana Corporation (the "Corporation"):

1. We have evaluated the Corporation's reserves data as at December 31, 2010 prepared in accordance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") of the Canadian Securities Administrators. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2010:

Independent Qualified Reserves Evaluator	Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) (US$millions)
McDaniel & Associates Consultants Ltd.	January 10, 2011	Canada	$3,795
GLJ Petroleum Consultants Ltd.	January 12, 2011	Canada	$9,717
Netherland, Sewell & Associates, Inc.	January 7, 2011	United States	$10,465
DeGolyer and MacNaughton	January 26, 2011	United States	$7,236
Total			**$31,213**

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

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

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

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

(signed) GLJ Petroleum Consultants Ltd.
Calgary, Alberta, Canada

(signed) Netherland, Sewell & Associates, Inc.
Dallas, Texas, U.S.A.

(signed) DeGolyer and MacNaughton
Dallas, Texas, U.S.A.

February 8, 2011

Appendix C - Report of Management and Directors on Reserves Data and Other Information (Canadian Protocol)

Management of Encana Corporation (the "Corporation") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs, prepared in accordance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") of the Canadian Securities Administrators.

Independent qualified reserves evaluators have evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the board of directors of the Corporation, which is comprised exclusively of non-management and unrelated directors, has:

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

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

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

The board of directors of the Corporation (the "Board of Directors") has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information prepared in accordance with the requirements of NI 51-101 contained in the annual information form of the Corporation;

(b) the filing of the report of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

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

(signed) Randall K. Eresman
President & Chief Executive Officer

(signed) Robert A. Grant
Executive Vice-President,
Corporate Development, EH&S and Reserves

(signed) David P. O'Brien
Director and Chairman of the Board

(signed) Claire S. Farley
Director and Chair of the Reserves Committee

February 9, 2011

Appendix D - U.S. Protocol Disclosure of Reserves Data and Other Oil and Gas Information

In this Appendix, Encana provides select disclosure of its reserves and other oil and gas information prepared in accordance with U.S. disclosure requirements. See “Note Regarding Reserves Data and Other Oil and Gas Information”.

Since inception, Encana has retained IQREs to evaluate and prepare reports on 100 percent of Encana’s natural gas and liquids reserves annually. For further information regarding the reserves process, see “Reserves and Other Oil and Gas Information” in this annual information form.

The standards of the SEC require that proved reserves be estimated using existing economic conditions (constant pricing). Effective January 1, 2010, the SEC amended its oil and gas reporting requirements. The amendments included changing the price used to calculate reserves from a year-end single day price to a historical 12-month average price and permitting optional disclosure of the sensitivity of reserves to price. As a result, Encana’s SEC constant prices for 2009 and 2010 utilized the 12-month average price and the 2008 SEC constant price utilized the year-end single day price.

Net Proved Reserves (U.S. Protocol)

Natural Gas Reserves

In 2010, Encana’s proved natural gas reserves increased by approximately 20 percent, largely as a result of successful development and delineation activity as well as higher 12-month average prices. Technical revisions were positive. Additions excluding purchase and sale of reserves, totaled 3,542 billion cubic feet, of which approximately two-thirds were in the U.S. and the balance was in Canada.

In 2009, Encana’s proved natural gas reserves decreased by approximately 19 percent, largely as a result of low 12-month average prices and the Split Transaction. Approximately 75 percent of the decrease attributable to negative revisions was a direct result of low 12-month average prices and approximately 80 percent of the sale of reserves in place was associated with the Split Transaction. Technical revisions were not significant. Extensions and discoveries were 2,132 billion cubic feet, of which approximately two-thirds was in the U.S. and the balance was in Canada.

In 2008, Encana’s proved natural gas reserves increased by approximately 3 percent as a result of successful exploration and development drilling, which resulted in extensions and discoveries of 1,966 billion cubic feet. Approximately two-thirds of extensions and discoveries were in Canada with the balance being in the U.S. Purchase and sale of reserves in place were not material.

Liquids Reserves

In 2010, Encana’s proved crude oil and natural gas liquids reserves increased by approximately 21 percent as a result of activities and plans to further capture additional associated liquids from natural gas production.

In 2009, Encana’s proved crude oil and natural gas liquids reserves decreased by approximately 77 percent and Encana’s bitumen reserves were divested, substantially all as a result of the Split Transaction.

In 2008, Encana’s proved crude oil and natural gas liquids reserves, including bitumen, increased approximately 8 percent, largely as a result of positive revisions associated with the Company’s interests in Foster Creek and Christina Lake, which were transferred to Cenovus as part of the Split Transaction.

Net Proved Reserves [1,2,3]
(SEC Constant Pricing; After Royalties)

	Natural Gas *(Bcf)*			Crude Oil and Natural Gas Liquids *(MMbbls)*			Bitumen [4] *(MMbbls)*
	Canada	United States	Total	Canada	United States	Total	Canada
2008							
Beginning of year	7,292	6,008	13,300	273.4	58.3	331.7	595.5
Revisions and improved recovery	148	(166)	(18)	27.9	(3.6)	24.3	84.9
Extensions and discoveries	1,311	655	1,966	17.0	3.8	20.8	-
Purchase of reserves in place	32	7	39	0.2	0.0	0.2	-
Sale of reserves in place	(129)	(75)	(204)	(0.9)	(2.0)	(2.9)	-
Production	(807)	(598)	(1,405)	(32.0)	(4.9)	(36.9)	(12.0)
End of year	7,847	5,831	13,678	285.6	51.6	337.2	668.4
Developed	4,945	3,720	8,665	208.5	33.9	242.4	125.9
Undeveloped	2,902	2,111	5,013	77.1	17.7	94.8	542.5
Total	**7,847**	**5,831**	**13,678**	**285.6**	**51.6**	**337.2**	**668.4**
2009							
Beginning of year	7,847	5,831	13,678	285.6	51.6	337.2	668.4
Revisions and improved recovery [5]	(755)	(845)	(1,600)	7.3	(12.6)	(5.3)	(87.6)
Extensions and discoveries	726	1,406	2,132	12.5	6.5	19.0	159.4
Purchase of reserves in place	28	-	28	0.5	-	0.5	-
Sale of reserves in place [6]	(1,772)	(89)	(1,861)	(243.2)	(0.2)	(243.4)	(725.1)
Production	(725)	(590)	(1,315)	(27.2)	(4.1)	(31.3)	(15.1)
End of year	5,349	5,713	11,062	35.5	41.2	76.7	-
Developed	2,927	3,571	6,498	25.1	25.8	50.9	-
Undeveloped	2,422	2,142	4,564	10.4	15.4	25.8	-
Total	**5,349**	**5,713**	**11,062**	**35.5**	**41.2**	**76.7**	**-**
2010							
Beginning of year	5,349	5,713	11,062	35.5	41.2	76.7	-
Revisions and improved recovery	150	517	667	13.6	0.2	13.8	-
Extensions and discoveries	1,067	1,808	2,875	11.5	4.7	16.2	-
Purchase of reserves in place	116	81	197	0.4	0.5	0.9	-
Sale of reserves in place	(82)	(257)	(339)	(1.9)	(4.9)	(6.8)	-
Production	(483)	(679)	(1,162)	(4.8)	(3.5)	(8.3)	-
End of year	6,117	7,183	13,300	54.3	38.2	92.5	-
Developed	3,132	3,678	6,810	24.9	24.0	48.9	-
Undeveloped	2,985	3,505	6,490	29.4	14.2	43.6	-
Total	**6,117**	**7,183**	**13,300**	**54.3**	**38.2**	**92.5**	**-**

Notes:

(1) Definitions:

a. Net reserves are the remaining reserves of Encana, after deduction of estimated royalties and including royalty interests.

b. Proved oil and gas reserves are those quantities of oil and gas which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

c. Developed oil and gas reserves are reserves of any category that are expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

d. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2) Encana does not file any estimates of total net proved natural gas and liquids reserves with any U.S. federal authority or agency other than the SEC.

(3) 2008 is reported using the year-end single day price as at December 31, 2008; as a result of amended SEC rules, 2009 and 2010 are reported using 12-month average pricing.

(4) Encana's disclosure of bitumen reserve volumes is in accordance with amended SEC rules regarding disclosure by final products.

(5) Revisions and improved recovery includes revisions due to price. Approximately 75 percent of the negative revisions to natural gas in 2009 were attributable to the significantly lower prices in effect for SEC reporting purposes.

(6) The transfer of Encana's Canadian Plains and Integrated Oil Divisions' upstream assets to Cenovus, effective November 30, 2009 pursuant to the Split Transaction, accounts for approximately 80 percent of the sale of reserves in place for natural gas and substantially all of the sale of reserves in place for crude oil and natural gas liquids and for bitumen during 2009.

Pricing Assumptions (SEC Constant Pricing)

The following reference prices were utilized in the determination of reserves and future net revenue:

	Natural Gas		Crude Oil and Natural Gas Liquids	
	Henry Hub *($/MMBtu)*	AECO *(C$/MMBtu)*	WTI *($/bbl)*	Edmonton [1] *(C$/bbl)*
Reserve Pricing [2,3,4]				
2008	5.71	6.22	44.60	44.27
2009	3.87	3.77	61.18	65.64
2010	4.38	4.03	79.43	76.22

Notes:

(1) Mixed Sweet Blend at Edmonton.
(2) 2010 and 2009 reference prices are 12-month average prices.
(3) 2008 reference prices were based on the year-end single day product prices.
(4) All prices were held constant in all future years when estimating net revenues and reserves.

Sensitivity of 2010 Reserves to Prices

The following table summarizes Encana's estimates of its proved reserves as at December 31, 2010 based on the 2010 12-month average prices ("SEC Constant Pricing case") and on the prices set forth below:

	Natural Gas *(Bcf)*			Crude Oil and Natural Gas Liquids *(MMbbls)*		
	Canada	United States	Total	Canada	United States	Total
Price Case						
SEC Constant Pricing case	6,117	7,183	13,300	54.3	38.2	92.5
Business case (forecast prices)	6,298	7,477	13,775	54.8	38.5	93.3
Difference versus SEC case	3.0%	4.1%	3.6%	0.9%	0.8%	0.9%

The business case assumes the following forecast prices: natural gas – Henry Hub $4.73/MMBtu in 2011 increasing to $6.63/MMBtu in 2021 and thereafter, and AECO C$4.35/MMBtu in 2011 increasing to C$6.48/MMBtu in 2021 and thereafter; crude oil – WTI $79.53/bbl increasing to $83.72/bbl in 2016 and thereafter and Edmonton Mixed Sweet C$81.93/bbl increasing to C$88.37/bbl in 2016 and thereafter. The forecast pricing assumptions in this business case were provided by Encana and are the same pricing assumptions used for the Canadian forecast prices included in "Pricing Assumptions (Forecast Prices)" in Appendix A to this annual information form.

Proved Undeveloped Reserves

Encana's proved undeveloped natural gas reserves represented approximately 49 percent of total proved natural gas reserves at December 31, 2010, an increase from approximately 41 percent at December 31, 2009. At December 31, 2010, approximately 47 percent of Encana's proved crude oil and liquids reserves were proved undeveloped, an increase from approximately 34 percent at December 31, 2009. These increases in undeveloped reserves were predicated on technical merit, commercial considerations and development plans. All of the proved undeveloped reserves at December 31, 2010 are scheduled for development within the next five years in both Canada and the United States.

During 2010, approximately 637 billion cubic feet equivalent of proved undeveloped reserves were converted to proved developed. Investments made during 2010 to convert proved undeveloped reserves to proved developed reserves were approximately $1.4 billion.

At December 31, 2010, the proved undeveloped reserves which have remained undeveloped for five years or more in both Canada and the United States were not material.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, constant price and cost assumptions were applied to Encana's annual future production from proved reserves to determine cash inflows. Future production and development costs assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by Encana's independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted to the extent provided by contractual arrangements, such as price risk management activities, in existence at year-end and to account for asset retirement obligations and future income taxes.

Encana cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of Encana's oil and gas properties, nor the future net cash flows expected to be generated from such properties. The discounted future net cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates. The computation also excludes values attributable to Encana's Market Optimization interests.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves [1]

($ millions)	Canada [2]			United States		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Future cash inflows	25,535	19,321	64,308	29,428	18,573	26,620
Less future:						
Production costs	8,676	6,296	23,017	6,894	4,862	6,079
Development costs	4,971	4,065	9,800	7,539	4,429	5,227
Asset retirement obligation payments	1,876	1,508	2,995	605	640	488
Income taxes	920	659	5,746	2,966	707	2,961
Future net cash flows	9,092	6,793	22,750	11,424	7,935	11,865
Less 10% annual discount for estimated timing of cash flows	3,803	2,704	10,036	5,277	3,592	5,218
Discounted future net cash flows	**5,289**	**4,089**	**12,714**	**6,147**	**4,343**	**6,647**

($ millions)	Total [2]		
	2010	**2009**	**2008**
Future cash inflows	54,963	37,894	90,928
Less future:			
Production costs	15,570	11,158	29,096
Development costs	12,510	8,494	15,027
Asset retirement obligation payments	2,481	2,148	3,483
Income taxes	3,886	1,366	8,707
Future net cash flows	20,516	14,728	34,615
Less 10% annual discount for estimated timing of cash flows	9,080	6,296	15,254
Discounted future net cash flows	**11,436**	**8,432**	**19,361**

Notes:

(1) 2010 and 2009 future net cash flows have been calculated using 12-month average prices. In 2008, future net cash flows were calculated using the 2008 year-end price.

(2) 2008 estimates of future net cash flows included the cash flows from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets). These operations were transferred to Cenovus as part of the Split Transaction.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves [(1)]

($ millions)	Canada [(2)] 2010	Canada 2009	Canada 2008	United States 2010	United States 2009	United States 2008
Balance, beginning of year	4,089	12,714	22,664	4,343	6,647	9,483
Changes resulting from:						
Sales of oil and gas produced during the period	(2,034)	(5,609)	(7,346)	(2,919)	(3,442)	(4,125)
Discoveries and extensions, net of related costs	975	1,294	2,031	1,243	629	904
Purchases of proved reserves in place	146	16	58	77	-	14
Sales and transfers of proved reserves in place	(96)	(6,492)	(321)	(198)	(62)	(197)
Net change in prices and production costs	1,647	(1,825)	(14,632)	3,831	(1,446)	(4,204)
Revisions to quantity estimates	174	(1,242)	1,736	610	(1,567)	667
Accretion of discount	433	1,572	2,905	465	827	1,346
Previously estimated development costs incurred net of change in future development costs	216	737	1,923	(289)	1,474	315
Other	(28)	150	321	144	(26)	88
Net change in income taxes	(233)	2,774	3,375	(1,160)	1,309	2,356
Balance, end of year	**5,289**	**4,089**	**12,714**	**6,147**	**4,343**	**6,647**

($ millions)	Total [(1,2)] 2010	Total 2009	Total 2008
Balance, beginning of year	8,432	19,361	32,147
Changes resulting from:			
Sales of oil and gas produced during the period	(4,953)	(9,051)	(11,471)
Discoveries and extensions, net of related costs	2,218	1,923	2,935
Purchases of proved reserves in place	223	16	72
Sales and transfers of proved reserves in place	(294)	(6,554)	(518)
Net change in prices and production costs	5,478	(3,271)	(18,836)
Revisions to quantity estimates	784	(2,809)	2,403
Accretion of discount	898	2,399	4,251
Previously estimated development costs incurred net of change in future development costs	(73)	2,211	2,238
Other	116	124	409
Net change in income taxes	(1,393)	4,083	5,731
Balance, end of year	**11,436**	**8,432**	**19,361**

Notes:

(1) 2010 and 2009 future net cash flows have been calculated using 12-month average prices. In 2008, future net cash flows were calculated using the 2008 year-end price.

(2) Results prior to November 30, 2009 include reserves from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Results of Operations

($ millions)	Canada [1]			United States		
	2010	2009	2008	2010	2009	2008
Oil and gas revenues, net of royalties, and transportation	2,632	6,835	8,848	3,613	4,007	5,127
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	598	1,226	1,502	694	565	1,002
Depreciation, depletion and amortization	1,242	1,980	2,198	1,912	1,561	1,691
Operating income (loss)	792	3,629	5,148	1,007	1,881	2,434
Income taxes	223	1,059	1,502	365	698	937
Results of operations	**569**	**2,570**	**3,646**	**642**	**1,183**	**1,497**

($ millions)	Other			Total [1]		
	2010	2009	2008	2010	2009	2008
Oil and gas revenues, net of royalties, and transportation	-	-	2	6,245	10,842	13,977
Less:						
Operating costs, production and mineral taxes, and accretion of asset retirement obligations	-	-	(2)	1,292	1,791	2,502
Depreciation, depletion and amortization	10	28	39	3,164	3,569	3,928
Operating income (loss)	(10)	(28)	(35)	1,789	5,482	7,547
Income taxes	-	-	-	588	1,757	2,439
Results of operations	**(10)**	**(28)**	**(35)**	**1,201**	**3,725**	**5,108**

Note:

(1) Results of Operations prior to November 30, 2009 include Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Capitalized Costs and Costs Incurred

Capitalized Costs

($ millions)	Canada (1) 2010	2009	2008	United States 2010	2009	2008
Proved oil and gas properties	24,972	21,459	33,466	21,944	19,843	15,755
Unproved oil and gas properties	1,114	728	870	1,043	1,178	3,399
Total capital cost	26,086	22,187	34,336	22,987	21,021	19,154
Accumulated DD&A	13,435	11,586	17,348	9,024	7,092	5,511
Net capitalized costs	**12,651**	**10,601**	**16,988**	**13,963**	**13,929**	**13,643**

($ millions)	Other 2010	2009	2008	Total (1) 2010	2009	2008
Proved oil and gas properties	-	-	-	46,916	41,302	49,221
Unproved oil and gas properties	167	157	122	2,324	2,063	4,391
Total capital cost	167	157	122	49,240	43,365	53,612
Accumulated DD&A	167	147	112	22,626	18,825	22,971
Net capitalized costs	**-**	**10**	**10**	**26,614**	**24,540**	**30,641**

Note:
(1) Results prior to November 30, 2009 include capitalized costs from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Costs Incurred

($ millions)	Canada (1) 2010	2009	2008	United States 2010	2009	2008
Acquisitions						
Unproved	395	46	32	97	46	1,006
Proved	197	178	119	44	-	17
Total acquisitions	592	224	151	141	46	1,023
Exploration costs	58	129	474	198	133	197
Development costs	2,153	2,588	3,485	2,301	1,688	2,485
Total costs incurred	**2,803**	**2,941**	**4,110**	**2,640**	**1,867**	**3,705**

($ millions)	Other 2010	2009	2008	Total (1) 2010	2009	2008
Acquisitions						
Unproved	-	-	-	492	92	1,038
Proved	-	-	-	241	178	136
Total acquisitions	-	-	-	733	270	1,174
Exploration costs	-	2	14	256	264	685
Development costs	-	-	-	4,454	4,276	5,970
Total costs incurred	**-**	**2**	**14**	**5,443**	**4,810**	**7,829**

Note:
(1) Results prior to November 30, 2009 include costs incurred from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Developed and Undeveloped Landholdings

The following table summarizes Encana's developed, undeveloped and total landholdings as at December 31, 2010.

Landholdings [1 - 7]

(thousands of acres)		Developed Gross	Developed Net	Undeveloped Gross	Undeveloped Net	Total Gross	Total Net
Canada							
Alberta	— Fee	2,270	2,270	1,266	1,266	3,536	3,536
	— Crown	1,490	862	1,663	1,353	3,153	2,215
	— Freehold	299	169	106	62	405	231
		4,059	3,301	3,035	2,681	7,094	5,982
British Columbia	— Crown	1,001	889	2,703	2,176	3,704	3,065
	— Freehold	-	-	7	-	7	-
		1,001	889	2,710	2,176	3,711	3,065
Newfoundland and Labrador	— Crown	-	-	35	2	35	2
Nova Scotia	— Crown	21	21	20	9	41	30
Northwest Territories	— Crown	-	-	45	12	45	12
Total Canada		**5,081**	**4,211**	**5,845**	**4,880**	**10,926**	**9,091**
United States							
Colorado	— Federal/State	184	172	518	482	702	654
	— Freehold	108	98	102	90	210	188
	— Fee	3	3	13	13	16	16
		295	273	633	585	928	858
Texas	— Federal/State	10	4	171	167	181	171
	— Freehold	158	115	360	253	518	368
	— Fee	-	-	4	2	4	2
		168	119	535	422	703	541
Louisiana	— Federal/State	1	1	3	2	4	3
	— Freehold	86	50	401	257	487	307
	— Fee	18	14	69	48	87	62
		105	65	473	307	578	372
Michigan	— Federal/State	-	-	364	364	364	364
	— Freehold	-	-	60	60	60	60
		-	-	424	424	424	424
Wyoming	— Federal/State	66	47	278	231	344	278
	— Freehold	5	4	14	11	19	15
		71	51	292	242	363	293
Other	— Federal/State	2	1	24	19	26	20
	— Freehold	1	1	37	27	38	28
	— Fee	-	-	60	52	60	52
		3	2	121	98	124	100
Total United States		**642**	**510**	**2,478**	**2,078**	**3,120**	**2,588**
International							
Azerbaijan		-	-	346	17	346	17
Australia		-	-	104	40	104	40
Total International		**-**	**-**	**450**	**57**	**450**	**57**
Total		**5,723**	**4,721**	**8,773**	**7,015**	**14,496**	**11,736**

Notes:

(1) Fee lands are those lands in which Encana has a fee simple interest in the mineral rights and has either: (i) not leased out all of the mineral zones; or (ii) retained a working interest; or (iii) one or more substances or products that have not been leased. The current fee lands acreage summary includes all fee titles owned by Encana that have one or more zones that remain unleased or available for development.
(2) This table excludes approximately 3 million gross acres of fee lands with one or more substances or products under lease or sublease, reserving to Encana royalties or other interests.
(3) Crown/Federal/State lands are those owned by the federal, provincial or state government or the First Nations, in which Encana has purchased a working interest lease.
(4) Freehold lands are owned by individuals (other than a government or Encana), in which Encana holds a working interest lease.
(5) Gross acres are the total area of properties in which Encana has an interest.
(6) Net acres are the sum of Encana's fractional interest in gross acres.
(7) Undeveloped acreage refers to those acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

Exploration and Development Activities

The following tables summarize Encana's gross participation and net interest in wells drilled for the periods indicated.

Exploration Wells Drilled [1,2]

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Gross**	**Net**
2010											
Canadian Division	22	15	-	-	-	-	22	15	31	53	15
USA Division	34	15	-	-	2	2	36	17	-	36	17
Total	**56**	**30**	**-**	**-**	**2**	**2**	**58**	**32**	**31**	**89**	**32**
2009											
Canadian Division	34	24	1	1	-	-	35	25	25	60	25
USA Division	8	4	-	-	1	-	9	4	-	9	4
	42	28	1	1	1	-	44	29	25	69	29
Canada – Other [3]	-	-	4	4	-	-	4	4	8	12	4
Total	**42**	**28**	**5**	**5**	**1**	**-**	**48**	**33**	**33**	**81**	**33**
2008											
Canadian Division	70	54	8	5	-	-	78	59	69	147	59
USA Division	26	14	-	-	-	-	26	14	-	26	14
	96	68	8	5	-	-	104	73	69	173	73
Canada – Other [3]	5	3	1	1	2	1	8	5	34	42	5
Other	-	-	-	-	3	1	3	1	-	3	1
Total	**101**	**71**	**9**	**6**	**5**	**2**	**115**	**79**	**103**	**218**	**79**

Notes:

(1) "Gross" wells are the total number of wells in which Encana has an interest.
(2) "Net" wells are the number of wells obtained by aggregating Encana's working interest in each of its gross wells.
(3) Wells drilled from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets) were part of the assets transferred to Cenovus as part of the November 30, 2009 Split Transaction.

Development Wells Drilled [1,2]

	Gas		Oil		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2010 [3]											
Canadian Division	1,270	1,190	1	1	-	-	1,271	1,191	203	1,474	1,191
USA Division	748	428	-	-	4	3	752	431	144	896	431
Total	**2,018**	**1,618**	**1**	**1**	**4**	**3**	**2,023**	**1,622**	**347**	**2,370**	**1,622**
2009											
Canadian Division	731	672	3	2	-	-	734	674	143	877	674
USA Division	495	382	-	-	5	4	500	386	55	555	386
	1,226	1,054	3	2	5	4	1,234	1,060	198	1,432	1,060
Canada – Other [4]	560	507	144	120	8	8	712	635	255	967	635
Total	**1,786**	**1,561**	**147**	**122**	**13**	**12**	**1,946**	**1,695**	**453**	**2,399**	**1,695**
2008											
Canadian Division	1,088	989	17	16	-	-	1,105	1,005	329	1,434	1,005
USA Division	904	736	-	-	-	-	904	736	378	1,282	736
	1,992	1,725	17	16	-	-	2,009	1,741	707	2,716	1,741
Canada – Other [4]	1,502	1,385	146	113	11	11	1,659	1,509	544	2,203	1,509
Total	**3,494**	**3,110**	**163**	**129**	**11**	**11**	**3,668**	**3,250**	**1,251**	**4,919**	**3,250**

Notes:

(1) "Gross" wells are the total number of wells in which Encana has an interest.

(2) "Net" wells are the number of wells obtained by aggregating Encana's working interest in each of its gross wells.

(3) At December 31, 2010, Encana was in the process of drilling the following exploratory and development wells: approximately 21 gross wells (21 net wells) in Canada and approximately 75 gross wells (49 net wells) in the U.S.

(4) Wells drilled from Canada – Other (former Canadian Plains and former Integrated Oil – Canada assets) were part of the assets transferred to Cenovus as part of the November 30, 2009 Split Transaction.

Production Volumes (After Royalties)

The following tables summarize the net daily average production volumes for Encana for the periods indicated.

Production Volumes (After Royalties)

	2010				
(average daily)	**Annual**	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas *(MMcf/d)*					
Canadian Division	1,323	1,395	1,390	1,327	1,177
USA Division	1,861	1,835	1,791	1,875	1,946
	3,184	3,230	3,181	3,202	3,123
Liquids *(bbls/d)*					
Canadian Division	13,149	11,327	14,262	13,462	13,558
USA Division	9,638	9,206	9,142	10,112	10,108
	22,787	20,533	23,404	23,574	23,666
Total Canadian & USA Divisions *(MMcfe/d)*	**3,321**	**3,353**	**3,322**	**3,344**	**3,265**
Canadian Division Total *(MMcfe/d)*	1,402	1,463	1,476	1,408	1,258
USA Division Total *(MMcfe/d)*	1,919	1,890	1,846	1,936	2,007
Total Canadian & USA Divisions *(MMcfe/d)*	**3,321**	**3,353**	**3,322**	**3,344**	**3,265**

(average daily)	**2009**	**2008**
Produced Gas *(MMcf/d)*		
Canadian Division (1)	1,224	1,300
USA Division	1,616	1,633
	2,840	2,933
Canada - Other	762	905
Total Produced Gas (2)	3,602	3,838
Liquids *(bbls/d)*		
Canadian Division (1)	15,880	19,980
USA Division	11,317	13,350
	27,197	33,330
Canada - Other	99,900	100,250
Total Liquids (2)	127,097	133,580
Total *(MMcfe/d)* (2)	**4,365**	**4,639**
Canadian Division Total (1) *(MMcfe/d)*	1,319	1,419
USA Division Total *(MMcfe/d)*	1,684	1,713
Total Canadian & USA Divisions *(MMcfe/d)*	**3,003**	**3,132**

Notes:

(1) Excludes results for Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

(2) Includes results for Canada – Other.

Per-Unit Results (After Royalties)

The following tables summarize the net per-unit results for Encana for the periods indicated, which exclude the impact of realized hedging.

Netbacks by Current Divisions & Country (After Royalties)

	2010				
	Annual	**Q4**	**Q3**	**Q2**	**Q1**
Produced Gas *($/Mcf)*					
Canadian Division					
Price, after royalties	4.10	3.73	3.69	3.92	5.21
Production and mineral taxes	0.01	-	0.02	0.02	0.01
Transportation	0.40	0.40	0.39	0.38	0.41
Operating	1.09	1.21	0.96	1.01	1.20
	2.60	2.12	2.32	2.51	3.59
USA Division					
Price, after royalties	4.73	4.08	4.57	4.45	5.78
Production and mineral taxes	0.27	0.24	0.25	0.25	0.35
Transportation	0.97	0.98	1.00	0.97	0.95
Operating	0.58	0.59	0.62	0.62	0.48
	2.91	2.27	2.70	2.61	4.00
Total Canadian & USA Divisions					
Price, after royalties	4.47	3.93	4.19	4.23	5.56
Production and mineral taxes	0.16	0.13	0.15	0.15	0.22
Transportation	0.73	0.73	0.74	0.73	0.74
Operating	0.79	0.86	0.77	0.78	0.75
	2.79	**2.21**	**2.53**	**2.57**	**3.85**
Liquids *($/bbl)*					
Canadian Division					
Price, after royalties	64.79	69.24	59.44	63.80	67.71
Production and mineral taxes	0.44	0.51	0.37	0.53	0.35
Transportation	0.82	0.69	0.93	1.10	0.53
Operating	3.24	4.03	2.27	2.22	4.67
	60.29	64.01	55.87	59.95	62.16
USA Division					
Price, after royalties	69.35	73.27	66.38	70.62	67.18
Production and mineral taxes	6.69	7.43	6.42	6.68	6.25
Transportation	-	-	-	-	-
	62.66	65.84	59.96	63.94	60.93
Total Canadian & USA Divisions					
Price, after royalties	66.72	71.05	62.15	66.73	67.48
Production and mineral taxes	3.08	3.61	2.74	3.17	2.87
Transportation	0.47	0.38	0.57	0.63	0.30
Operating	1.87	2.22	1.38	1.26	2.67
	61.30	**64.84**	**57.46**	**61.67**	**61.64**
Total Netback *($/Mcfe)*					
Canadian Division					
Price, after royalties	4.47	4.10	4.05	4.30	5.60
Production and mineral taxes	0.02	-	0.02	0.03	0.01
Transportation	0.38	0.39	0.38	0.37	0.39
Operating	1.06	1.19	0.93	0.97	1.17
	3.01	2.52	2.72	2.93	4.03
USA Division					
Price, after royalties	4.94	4.32	4.76	4.68	5.94
Production and mineral taxes	0.30	0.27	0.27	0.28	0.38
Transportation	0.95	0.95	0.97	0.94	0.92
Operating	0.56	0.58	0.61	0.60	0.46
	3.13	2.52	2.91	2.86	4.18
Total Canadian & USA Divisions					
Price, after royalties	4.74	4.22	4.45	4.52	5.81
Production and mineral taxes	0.18	0.15	0.16	0.17	0.23
Transportation	0.71	0.70	0.71	0.70	0.71
Operating	0.77	0.84	0.75	0.76	0.74
	3.08	**2.53**	**2.83**	**2.89**	**4.13**

Netbacks by Current Divisions (After Royalties)

	Annual Average	
	2009	**2008**
Produced Gas *($/Mcf)*		
Canadian Division [(1)]		
Price, after royalties	3.71	8.12
Production and mineral taxes	0.03	0.06
Transportation	0.33	0.42
Operating	1.13	1.15
	2.22	6.49
USA Division		
Price, after royalties	3.75	7.89
Production and mineral taxes	0.17	0.56
Transportation	0.90	0.84
Operating	0.55	0.59
	2.13	5.90
Total Canadian & USA Divisions		
Price, after royalties	3.73	7.99
Production and mineral taxes	0.11	0.34
Transportation	0.66	0.66
Operating	0.80	0.84
	2.16	**6.15**
Liquids *($/bbl)*		
Canadian Division [(1)]		
Price, after royalties	47.86	85.12
Production and mineral taxes	0.45	0.63
Transportation	1.06	1.64
Operating	3.62	5.41
	42.73	77.44
USA Division		
Price, after royalties	48.56	83.18
Production and mineral taxes	4.39	7.25
Transportation	-	-
	44.17	75.93
Total Canadian & USA Divisions		
Price, after royalties	48.15	84.38
Production and mineral taxes	2.09	3.27
Transportation	0.62	0.98
Operating	2.11	3.40
	43.33	**76.73**
Total Netback *($/Mcfe)*		
Canadian Division [(1)]		
Price, after royalties	4.02	8.63
Production and mineral taxes	0.03	0.06
Transportation	0.32	0.41
Operating	1.09	1.13
	2.58	7.03
USA Division		
Price, after royalties	3.92	8.17
Production and mineral taxes	0.19	0.59
Transportation	0.86	0.80
Operating	0.53	0.56
	2.34	6.22
Total Canadian & USA Divisions		
Price, after royalties	3.96	8.38
Production and mineral taxes	0.12	0.35
Transportation	0.63	0.62
Operating	0.78	0.82
	2.43	**6.59**

Note:

(1) Excludes results for Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

Netbacks by Country (After Royalties)

	Annual Average	
	2009	**2008**
Produced Gas *($/Mcf)*		
Canada [1]		
Price, after royalties	3.64	7.97
Production and mineral taxes	0.04	0.08
Transportation	0.26	0.35
Operating	0.98	1.03
	2.36	6.51
United States		
Price, after royalties	3.75	7.89
Production and mineral taxes	0.17	0.56
Transportation	0.90	0.84
Operating	0.55	0.59
	2.13	5.90
Total Encana [1]		
Price, after royalties	3.69	7.94
Production and mineral taxes	0.10	0.28
Transportation	0.55	0.56
Operating	0.79	0.84
	2.25	**6.26**
Liquids *($/bbl)*		
Canada [1]		
Price, after royalties	49.75	75.85
Production and mineral taxes	0.63	1.01
Transportation	1.53	1.70
Operating	9.21	10.57
	38.38	62.57
United States		
Price, after royalties	48.56	83.18
Production and mineral taxes	4.39	7.25
Transportation	0.00	0.00
	44.17	75.93
Total Encana [1]		
Price, after royalties	49.65	76.58
Production and mineral taxes	0.97	1.63
Transportation	1.39	1.53
Operating	8.39	9.55
	38.90	**63.87**
Total Netback *($/Mcfe)*		
Canada [1]		
Price, net of royalties	4.84	9.13
Production and mineral taxes	0.05	0.10
Transportation	0.26	0.33
Operating	1.12	1.21
	3.41	7.49
United States		
Price, after royalties	3.92	8.17
Production and mineral taxes	0.19	0.59
Transportation	0.86	0.80
Operating	0.53	0.56
	2.34	6.22
Total Encana [1]		
Price, after royalties	4.49	8.77
roduction and mineral taxes	0.11	0.28
Transportation	0.49	0.50
Operating	0.89	0.97
	3.00	**7.02**

Note:

(1) Results prior to November 30, 2009 include production from Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

The following tables summarize the impact of realized hedging on Encana's netbacks.

Impact of Realized Hedging on Encana's Canadian & USA Divisions Netbacks [(1)]

	2010				
	Annual	Q4	Q3	Q2	Q1
Canadian Division *($/Mcfe)*	0.93	1.02	0.94	1.16	0.55
USA Division *($/Mcfe)*	1.00	1.07	1.11	1.27	0.55
Total *($/Mcfe)*	0.97	1.05	1.04	1.22	0.55

	Annual Average	
	2009	2008
Canadian Division *($/Mcfe)*	2.93	(0.36)
USA Division *($/Mcfe)*	3.27	0.34
Total *($/Mcfe)*	3.12	0.03

Impact of Realized Hedging on Encana's Total Netbacks [(2)]

	2010				
	Annual	Q4	Q3	Q2	Q1
Natural Gas *($/Mcf)*	1.01	1.10	1.08	1.27	0.58
Liquids *($/bbl)*	(0.60)	(2.14)	(0.36)	0.32	(0.41)
Total *($/Mcfe)*	0.97	1.05	1.04	1.22	0.55

	Annual Average	
	2009	2008
Natural Gas *($/Mcf)*	3.33	(0.02)
Liquids *($/bbl)*	0.83	(5.46)
Total *($/Mcfe)*	2.77	(0.17)

Notes:

(1) Results prior to November 30, 2009 exclude Canada – Other (former Canadian Plains and former Integrated Oil – Canada operations). These operations were transferred to Cenovus as part of the Split Transaction.

(2) Results prior to November 30, 2009, include production from Canada – Other.

Appendix E - Audit Committee Mandate

Last updated December 8, 2009. Last reviewed December 6, 2010.

I. PURPOSE

The Audit Committee (the "Committee") is appointed by the Board of Directors of Encana Corporation ("the Corporation") to assist the Board in fulfilling its oversight responsibilities.

The Committee's primary duties and responsibilities are to:

- Review management's identification of principal financial risks and monitor the process to manage such risks.
- Oversee and monitor the Corporation's compliance with legal and regulatory requirements.
- Receive and review the reports of the Audit Committee of any subsidiary with public securities.
- Oversee and monitor the integrity of the Corporation's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance.
- Oversee audits of the Corporation's financial statements.
- Oversee and monitor the qualifications, independence and performance of the Corporation's external auditors and internal auditing department.
- Provide an avenue of communication among the external auditors, management, the internal auditing department, and the Board of Directors.
- Report to the Board of Directors regularly.

The Committee has the authority to conduct any review or investigation appropriate to fulfilling its responsibilities. The Committee shall have unrestricted access to personnel and information, and any resources necessary to carry out its responsibility. In this regard, the Committee may direct internal audit personnel to particular areas of examination.

II. COMPOSITION AND MEETINGS

Committee Member's Duties in addition to those of a Director

The duties and responsibilities of a member of the Committee are in addition to those duties set out for a member of the Board of Directors.

Composition

The Committee shall consist of not less than three and not more than five directors as determined by the Board, all of whom shall qualify as independent directors pursuant to National Instrument 52-110 *Audit Committees* (as implemented by the Canadian Securities Administrators and as amended from time to time) ("NI 52-110").

All members of the Committee shall be financially literate, as defined in NI 52-110, and at least one member shall have accounting or related financial managerial expertise. In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

- An understanding of generally accepted accounting principles and financial statements;
- The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;

- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements, or experience actively supervising one or more persons engaged in such activities;
- An understanding of internal controls and procedures for financial reporting; and
- An understanding of audit committee functions.

Committee members may not, other than in their respective capacities as members of the Committee, the Board or any other committee of the Board, accept directly or indirectly any consulting, advisory or other compensatory fee from the Corporation or any subsidiary of the Corporation, or be an "affiliated person" (as such term is defined in the United States Securities Exchange Act of 1934, as amended (the "*Exchange Act*"), and the rules adopted by the U.S. Securities and Exchange Commission ("SEC") thereunder) of the Corporation or any subsidiary of the Corporation. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Corporation that are not contingent on continued service should be the only compensation an audit committee member receives from the Corporation.

At least one member shall have experience in the oil and gas industry.

Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

The non-executive Board Chairman shall be a non-voting member of the Committee. See Quorum for further details.

Appointment of Members

Committee members shall be appointed at a meeting of the Board, effective after the election of directors at the annual meeting of shareholders, provided that any member may be removed or replaced at any time by the Board and shall, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board.

The Nominating and Corporate Governance Committee will recommend for approval to the Board an unrelated Director to act as Chairman of the Committee. The Board shall appoint the Chairman of the Committee.

If the Chairman of the Committee is unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen to preside over the meeting by a majority of the members of the Committee present at such meeting.

The Chairman of the Committee presiding at any meeting of the Committee shall not have a casting vote.

The items pertaining to the Chairman in this section should be read in conjunction with the Committee Chair section of the *Chair of the Board of Directors and Committee Chair General Guidelines*.

Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Corporate Secretary or one of the Assistant Corporate Secretaries of the Corporation or such other person as the Corporate Secretary of the Corporation shall designate from time to time shall be the Secretary of the Committee and shall keep minutes of the meetings of the Committee.

Meetings

Committee meetings may, by agreement of the Chairman of the Committee, be held in person, by video conference, by means of telephone or by a combination of any of the foregoing.

The Committee shall meet at least quarterly. The Chairman of the Committee may call additional meetings as required. In addition, a meeting may be called by the non-executive Board Chairman, the President & Chief Executive Officer, or any member of the Committee or by the external auditors.

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Committee Chairman or by a majority of the members of the Committee.

The Committee may, by specific invitation, have other resource persons in attendance.

The President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer, the Executive Vice-President & Chief Accounting Officer and the Vice-President, Financial Compliance & Audit are expected to be available to attend the Committee's meetings or portions thereof.

Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 48 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Corporation.

A member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

Quorum

A majority of Committee members, present in person, by video conference, by telephone, or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member's presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

Minutes

Minutes of each Committee meeting should be succinct yet comprehensive in describing substantive issues discussed by the Committee. However, they should clearly identify those items of responsibilities scheduled by the Committee for the meeting that have been discharged by the Committee and those items of responsibilities that are outstanding.

Minutes of Committee meetings shall be sent to all Committee members and to the external auditors.

The full Board of Directors shall be kept informed of the Committee's activities by a report following each Committee meeting.

III. RESPONSIBILITIES

Review Procedures

Review and update the Committee's mandate annually, or sooner, where the Committee deems it appropriate to do so. Provide a summary of the Committee's composition and responsibilities in the Corporation's annual report or other public disclosure documentation.

Provide a summary of all approvals by the Committee of the provision of audit, audit-related, tax and other services by the external auditors for inclusion in the Corporation's annual report filed with the SEC.

Annual Financial Statements

1. Discuss and review with management and the external auditors the Corporation's and any subsidiary with public securities annual audited financial statements and related documents prior to their filing or distribution. Such review to include:

   a. The annual financial statements and related footnotes including significant issues regarding accounting principles, practices and significant management estimates and judgments, including any significant changes in the Corporation's selection or application of accounting principles, any major issues as to the adequacy of the Corporation's internal controls and any special steps adopted in light of material control deficiencies.

   b. Management's Discussion and Analysis.

   c. A review of the use of off-balance sheet financing including management's risk assessment and adequacy of disclosure.

   d. A review of the external auditors' audit examination of the financial statements and their report thereon.

   e. Review of any significant changes required in the external auditors' audit plan.

   f. A review of any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information.

   g. A review of other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

2. Review and formally recommend approval to the Board of the Corporation's:

   a. Year-end audited financial statements. Such review shall include discussions with management and the external auditors as to:

      (i) The accounting policies of the Corporation and any changes thereto.

      (ii) The effect of significant judgements, accruals and estimates.

      (iii) The manner of presentation of significant accounting items.

      (iv) The consistency of disclosure.

   b. Management's Discussion and Analysis.

   c. Annual Information Form as to financial information.

   d. All prospectuses and information circulars as to financial information.

   The review shall include a report from the external auditors about the quality of the most critical accounting principles upon which the Corporation's financial status depends, and which involve the most complex, subjective or significant judgemental decisions or assessments.

Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for public release) or formally recommend for approval to the Board the Corporation's:

   a. Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis.

   b. Any significant changes to the Corporation's accounting principles.

Review quarterly unaudited financial statements of any subsidiary of the Corporation with public securities prior to their distribution.

Other Financial Filings and Public Documents

4. Review and discuss with management financial information, including earnings press releases, the use of "pro forma" or non-GAAP financial information and earnings guidance, contained in any filings with the securities regulators or news releases related thereto (or provided to analysts or rating agencies) and consider whether the information is consistent with the information contained in the financial statements of the Corporation or any subsidiary with public securities. Such discussion may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made).

Internal Control Environment

5. Ensure that management, the external auditors, and the internal auditors provide to the Committee an annual report on the Corporation's control environment as it pertains to the Corporation's financial reporting process and controls.

6. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Corporation.

7. Review significant findings prepared by the external auditors and the internal auditing department together with management's responses.

8. Review in consultation with the internal auditors and the external auditors the degree of coordination in the audit plans of the internal auditors and the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud, or other illegal acts. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

Other Review Items

9. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the internal auditor or the external auditors.

10. Review all related party transactions between the Corporation and any officers or directors, including affiliations of any officers or directors.

11. Review with the General Counsel, the head of internal audit and the external auditors the results of their review of the Corporation's monitoring compliance with each of the Corporation's published codes of business conduct and applicable legal requirements.

12. Review legal and regulatory matters, including correspondence with regulators and governmental agencies, that may have a material impact on the interim or annual financial statements, related corporation compliance policies, and programs and reports received from regulators or governmental agencies. Members from the Legal and Tax departments should be at the meeting in person to deliver their reports.

13. Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, and consider the results of any review of these areas by the internal auditors or the external auditors.

14. Ensure that the Corporation's presentations on net proved reserves have been reviewed with the Reserves Committee of the Board.

15. Review management's processes in place to prevent and detect fraud.

16. Review procedures for the receipt, retention and treatment of complaints received by the Corporation, including confidential, anonymous submissions by employees of the Corporation, regarding accounting, internal accounting controls, or auditing matters.

17. Review with the President & Chief Executive Officer, the Executive Vice-President & Chief Financial Officer of the Corporation and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Corporation's internal controls and procedures for financial reporting which could adversely affect the Corporation's ability to record, process, summarize and report financial information required to be disclosed by the Corporation in the reports that it files or submits under the Exchange Act or applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Corporation or other employees who have a significant role in the Corporation's internal controls and procedures for financial reporting.

18. Meet on a periodic basis separately with management.

External Auditors

19. Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Corporation. The external auditors shall report directly to the Committee.

20. Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chairman of the Committee or by a majority of the members of the Committee.

21. Review and discuss a report from the external auditors at least quarterly regarding:

    a. All critical accounting policies and practices to be used;

    b. All alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and

    c. Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

22. Obtain and review a report from the external auditors at least annually regarding:

    a. The external auditors' internal quality-control procedures.

    b. Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues.

    c. To the extent contemplated in the following paragraph, all relationships between the external auditors and the Corporation.

23. Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (i) receiving and reviewing, as part of the report described in the preceding paragraph, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the

Corporation and its affiliates, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

24. Review and evaluate:

   a. The external auditors' and the lead partner of the external auditors' team's performance, and make a recommendation to the Board of Directors regarding the reappointment of the external auditors at the annual meeting of the Corporation's shareholders or regarding the discharge of such external auditors.

   b. The terms of engagement of the external auditors together with their proposed fees.

   c. External audit plans and results.

   d. Any other related audit engagement matters.

   e. The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.

25. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 21 through 24, evaluate the external auditors' qualifications, performance and independence, including whether or not the external auditors' quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present its conclusions with respect to the external auditors to the Board.

26. Ensure the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

27. Set clear hiring policies for the Corporation's hiring of employees or former employees of the external auditors.

28. Consider with management and the external auditors the rationale for employing audit firms other than the principal external auditors.

29. Consider and review with the external auditors, management and the head of internal audit:

   a. Significant findings during the year and management's responses and follow-up thereto.

   b. Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response.

   c. Any significant disagreements between the external auditors or internal auditors and management.

   d. Any changes required in the planned scope of their audit plan.

   e. The resources, budget, reporting relationships, responsibilities and planned activities of the internal auditors.

   f. The internal audit department mandate.

   g. Internal audit's compliance with the Institute of Internal Auditors' standards.

Internal Audit Department and Independence

30. Meet on a periodic basis separately with the head of internal audit.

31. Review and concur in the appointment, compensation, replacement, reassignment, or dismissal of the head of internal audit.

32. Confirm and assure, annually, the independence of the internal audit department and the external auditors.

Approval of Audit and Non-Audit Services

33. Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors (subject to the *de minimus* exception for non-audit services described in the *Exchange Act* or applicable Canadian federal and provincial legislation and regulations which are approved by the Committee prior to the completion of the audit).

34. Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

35. If the pre-approvals contemplated in paragraphs 33 and 34 are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

36. Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 33 through 35. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

37. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 33 and 34, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee's responsibilities under the *Exchange Act* or applicable Canadian federal and provincial legislation and regulations to management.

Other Matters

38. Review and concur in the appointment, replacement, reassignment, or dismissal of the Chief Financial Officer.

39. Upon a majority vote of the Committee outside resources may be engaged where and if deemed advisable.

40. Report Committee actions to the Board of Directors with such recommendations, as the Committee may deem appropriate.

41. Conduct or authorize investigations into any matters within the Committee's scope of responsibilities. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and the carrying out of its duties.

42. The Corporation shall provide for appropriate funding, as determined by the Committee in its capacity as a committee of the Board, for payment (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation, (ii) of compensation to any advisors employed by the Committee and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

43. Obtain assurance from the external auditors that disclosure to the Committee is not required pursuant to the provisions of the *Exchange Act* regarding the discovery of illegal acts by the external auditors.

44. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

45. The Committee's performance shall be evaluated annually by the Nominating and Corporate Governance Committee of the Board of Directors.

46. Perform such other functions as required by law, the Corporation's mandate or bylaws, or the Board of Directors.

47. Consider any other matters referred to it by the Board of Directors.