Management's Discussion and Analysis
For the Year Ended December 31, 2011

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., dated February 15, 2012, should be read with our audited Consolidated Financial Statements and accompanying notes for the year ended December 31, 2011 ("Consolidated Financial Statements"). This MD&A contains forward-looking information about our current expectations, estimates and projections. For information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information, as well as definitions used in this MD&A, see the Advisory.

Management is responsible for preparing the MD&A, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviews the MD&A and recommends its approval by the Board.

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated. Effective January 1, 2011, we adopted International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. For all periods up to and including the year ended December 31, 2010, we prepared our Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("previous GAAP"). In accordance with the standard related to the first time adoption of IFRS ("IFRS 1"), our transition date to IFRS was January 1, 2010 and therefore the 2011 and 2010 information has been prepared in accordance with IFRS. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed by IFRS 1, has not been re-presented in accordance with IFRS. Production volumes are presented on a before royalties basis. Certain amounts in prior years have been reclassified to conform to the current year's IFRS presentation format.

WHERE TO FIND:

INTRODUCTION AND OVERVIEW OF CENOVUS ENERGY

We are a Canadian oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2011, we had a market capitalization of approximately $26 billion. We are in the business of developing, producing and marketing crude oil, natural gas and natural gas liquids ("NGLs") in Canada with refining operations in the United States. Our total 2011 average crude oil and NGLs production was in excess of 134,000 barrels per day and our average natural gas production was in excess of 650 MMcf per day. Our operations include oil sands projects in northern Alberta, including Foster Creek and Christina Lake. These two properties, which we operate and have a 50 percent ownership interest in, are located in the Athabasca Region and use steam-assisted gravity drainage ("SAGD") to extract crude oil. Also located within the Athabasca Region is our wholly owned Pelican Lake property, where we have an enhanced oil recovery project using polymer flood technology, as well as our emerging Grand Rapids SAGD project. In southern Saskatchewan, we inject carbon dioxide to enhance oil recovery at our Weyburn operation and are also developing our Bakken and Lower Shaunavon tight oil plays. We also have established conventional crude oil and natural gas production in Alberta. In addition to our upstream assets, we have 50 percent ownership in two refineries located in Illinois and Texas, U.S., enabling us to partially integrate our operations from crude oil production through to refined products such as gasoline, diesel and jet fuel, to mitigate the volatility associated with commodity price movements.

Our operational focus is to increase crude oil production, predominantly from Foster Creek, Christina Lake, Pelican Lake and our tight oil opportunities in Saskatchewan, and to continue the assessment of our emerging resource base. We have proven our expertise and low cost oil sands development approach. Our conventional natural gas production base is expected to generate reliable production and cash flow which will enable further development of our crude oil assets. In all of our operations, whether crude oil or natural gas, technology plays a key role in improving the way we extract the resources, increasing the amount recovered and reducing costs. Cenovus has a knowledgeable, experienced team committed to innovation. We embed environmental considerations into our business with the objective to ultimately lessen our environmental impact. We are advancing technologies that reduce the amount of water, natural gas and electricity consumed in our operations and minimize surface land disturbance.

Our strategy is to focus on the development of our substantial crude oil resources in Alberta and Saskatchewan. Our future opportunities are primarily based on the development of the land position that we hold in the Athabasca region in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 450 stratigraphic test wells each year for the next five years. In addition to our Foster Creek and Christina Lake oil sands projects, the next three emerging projects that we expect to develop in this area as well as our current ownership interests are as follows:

	Ownership Interest
Narrows Lake	50 percent [1]
Grand Rapids	100 percent
Telephone Lake	100 percent

[1] Approximate ownership interest

In June 2010, we submitted a joint application and Environmental Impact Assessment ("EIA") for our Narrows Lake property, which is located within the Christina Lake Region. This project is expected to have a gross production capacity of 130,000 barrels per day and be developed in up to three phases. Provided all regulatory requirements are met we anticipate receiving regulatory approval in the middle of 2012 with first production expected in 2016.

At our 100 percent owned Grand Rapids property, located within the Greater Pelican Region, a SAGD pilot project is underway. In December 2011, we filed a joint application and EIA for a commercial SAGD operation. The proposed project is expected to have a gross production capacity of 180,000 barrels per day.

Our 100 percent owned Telephone Lake property is located within the Borealis Region and in December 2011, we submitted a revised joint application and EIA. The Telephone Lake project is now expected to have an initial gross production capacity of 90,000 barrels per day.

We have a number of opportunities to deliver shareholder value, predominantly through production growth from our resource position in the oil sands and tight oil opportunities. Our business plan targets growing our net oil sands production to approximately 400,000 barrels per day by the end of 2021. By the end of 2016, we are also targeting crude oil production from Pelican Lake of 55,000 barrels per day as well as 65,000 to 75,000 barrels per day from our conventional oil operations in Saskatchewan and southern Alberta. In addition, we plan to assess the potential of new crude oil projects on our existing lands and new regions with a focus on tight oil opportunities. We are targeting total net crude oil production of approximately 500,000 barrels per day by the end of 2021.

To achieve these production targets, we expect our total annual capital investment to average between $3.0 and $3.5 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of balance sheet capacity.

Our natural gas production provides a reliable stream of operating cash flow and acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our refineries, which are operated by ConocoPhillips, an unrelated U.S. public company, enable us to moderate commodity price cycles by processing heavy oil, thus economically integrating our oil sands production. As part of our risk management program, we employ commodity hedging to enhance cash flow certainty. In addition to our strategy of growing net asset value, we expect to continue to pay meaningful and growing dividends as part of delivering a strong total shareholder return over the long-term.

OUR BUSINESS STRUCTURE

Our reportable segments are as follows:

- **Oil Sands**, which consists of Cenovus's producing bitumen assets at Foster Creek and Christina Lake, heavy oil assets at Pelican Lake, new resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and the Athabasca natural gas assets. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips.

- **Conventional**, which includes the development and production of conventional crude oil, natural gas and NGLs in Alberta and Saskatchewan, notably the carbon dioxide enhanced oil recovery project at Weyburn, and the Bakken and Lower Shaunavon crude oil properties.

- **Refining and Marketing**, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by ConocoPhillips. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

- **Corporate and Eliminations**, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments recorded at transfer prices based on current market prices and to unrealized intersegment profits in inventory.

OVERVIEW OF 2011

In 2011, we achieved the milestones that we set for the year. We completed our planned capital programs, met or exceeded our production targets, kept our capital and operating costs in line with expectations and ended the year in a stronger financial position than we started. In the third quarter, phase C at Christina Lake achieved first production ahead of schedule and capital expenditures below budget for the entire phase. We have accelerated planned first production from phases D and E at Christina Lake to commence in the fourth quarters of 2012 and 2013, respectively each about six months earlier than originally expected. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design. Construction of the coker and start up activities of the Coker and Refinery Expansion ("CORE") project at the Wood River Refinery were completed with total capital costs of US$3.8 billion (US$1.9 billion net to Cenovus), within 10 percent of its original budget. Demonstrating our strong resource base, our total bitumen, crude oil and NGLs proved reserves increased 22 percent to over 1.7 billion barrels and our best estimate bitumen economic contingent resources increased 34 percent to 8.2 billion barrels. Our operational performance in 2011 and consistent crude oil growth have increased our net asset value and we expect to reach our goal of doubling our December 2009 net asset value by the end of 2015.

OPERATIONAL RESULTS

Our average crude oil and NGLs production increased four percent to 134,239 barrels per day compared to 2010, primarily due to the start of production from phase C at Christina Lake in the third quarter of 2011, improved well performance and plant efficiency at Foster Creek as well as increased production from our Lower Shaunavon tight oil play. These production increases were partially offset by operational challenges including wet weather and flooding in southern Saskatchewan and Alberta and wild fires in northern Alberta which temporarily curtailed production at Pelican Lake. Our December 2011 average crude oil and NGLs production was 150,977 barrels per day, up 18 percent from the prior year.

At Christina Lake we received regulatory approval from the Alberta Energy Resources Conservation Board ("ERCB") for expansion phases E, F and G. This expansion approval, as well as the positive delineation results, added 270 million barrels of proved bitumen reserves.

Our best estimate bitumen economic contingent resources increased 2.1 billion barrels or approximately 34 percent from 2010. The substantial increase was primarily due to successful stratigraphic test well drilling, resulting in the conversion of prospective resources to contingent resources.

In the fourth quarter of 2011, we completed coker construction and start up activities of the CORE project at the Wood River Refinery. CORE capital expenditures were approximately US$3.8 billion (US$1.9 billion net to Cenovus), 10 percent higher than originally budgeted. Structured test runs undertaken to date have been successful, and a five percent increase to clean product yield has been achieved. Testing will continue through the first quarter of 2012, and the Wood River Refinery's total heavy crude oil processing capacity is expected to increase to between 200,000 to 220,000 barrels per day, enhancing our ability to integrate our growing bitumen production.

Other significant 2011 operational results compared to 2010 include:

- Foster Creek production averaging 54,868 barrels per day, an increase of seven percent from 2010;
- Christina Lake production averaging 11,665 barrels per day, an increase of 48 percent from 2010 and ended 2011 producing approximately 23,000 barrels per day;
- Lower Shaunavon average production more than doubling to 2,041 barrels per day;
- Pelican Lake production averaging 20,424 barrels per day, a decrease of 11 percent partly due to the temporary curtailment of production due to wild fires in the area which decreased production by approximately 500 barrels per day, a scheduled turnaround which reduced production by approximately 300 barrels per day and expected natural declines;
- Drilling 491 gross stratigraphic test wells, mainly in the first quarter, to support the next phases of expansion at Foster Creek and Christina Lake, gather data on the quality of our emerging projects and support regulatory applications;
- Commencing the regulatory approval process for two of our emerging projects with the filing of a regulatory application for a commercial SAGD operation at our Grand Rapids property with an expected gross production capacity of 180,000 barrels per day and filing a revised regulatory application for Telephone Lake with an expected initial gross production capacity of 90,000 barrels per day. With these applications filed we have 400,000 barrels per day of gross production capacity in the regulatory process;
- Applying for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G;
- Receiving approval from the Alberta Department of Energy ("ADOE") to include all previous capital investment for Foster Creek expansion phases F, G and H as part of our existing Foster Creek royalty calculation;
- Receiving partner approval for expansion phases F, G and H at Foster Creek and expansion phase E at Christina Lake; and
- Effectively managing the expected natural declines in our natural gas assets resulting in an absolute year over year production decline of 11 percent and a seven percent decrease, excluding the 2010 dispositions. While year over year production was down, production throughout 2011 remained relatively flat with low levels of capital investment.

FINANCIAL RESULTS

Throughout 2011, our financial results benefited from higher crude oil prices and a significant increase in refining crack spreads when compared to 2010. As a result of the increased crack spreads, we saw substantially improved operating cash flow from our Refining and Marketing segment. The higher average crude oil prices improved operating cash flow from our crude oil and NGLs operations, although price had a negative impact on our royalty expense as the Canadian dollar WTI price is used to calculate the royalty rates at our Oil Sands operations.

The financial highlights for 2011 compared to 2010 include:

- Revenues increasing $3,055 million, or 24 percent, primarily due to increased crude oil and NGLs production, improved refined product prices, a 16 percent increase in the average sales price for crude oil and NGLs, excluding financial hedging, higher condensate prices and volumes used for blending partially offset by decreased natural gas volumes and average sales prices;
- Operating cash flow of $981 million from Refining and Marketing, an increase of $905 million, primarily due to higher refining margins that resulted from both higher refined product pricing and discounted crude oil feedstock costs;
- Cash flow of $3,276 million, increasing 36 percent, primarily due to the significant increase in operating cash flow from Refining and Marketing and improved crude oil and NGLs production and average sales price;
- Our Conventional natural gas operations generating $623 million of operating cash flow in excess of the related capital investment, which partially funded the further development of our crude oil projects;
- Operating earnings increasing 55 percent or $440 million, primarily due to higher operating cash flow partially offset by increased general and administrative and income tax expenses (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures);
- Receiving approval from the ADOE to include all previous capital investment for Foster Creek expansion phases F, G and H as part of our existing Foster Creek royalty calculation resulting in a one-time reduction in royalty expense of approximately $65 million; and
- Paying a quarterly dividend of $0.20 per share.

STRATEGIC PLAN UPDATE

In 2011, we provided an update to our 10 year strategic plan with a focus on doubling our net asset value between 2010 and 2015. To achieve this goal our 10 year strategic plan now targets:

- Expected gross production capacity at Foster Creek, including phases F, G and H as well as future phases, of between 290,000 to 310,000 barrels per day, an increase of 55,000 to 75,000 barrels per day from the original estimate;
- Accelerating the timelines for production at Foster Creek phases G and H by approximately one year, to 2015 and 2016 respectively, and for production at Christina Lake phases D and E by approximately six months with production now expected at phase D in the fourth quarter of 2012 and at phase E in the fourth quarter of 2013;
- Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016;
- Increasing Conventional crude oil production in Saskatchewan and southern Alberta to approximately 65,000 to 75,000 barrels per day by the end of 2016; and
- Assessing the potential of new oil projects on our existing properties and in new regions with a focus on light oil opportunities.

OUR BUSINESS ENVIRONMENT

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows selected market benchmark prices and the U.S./Canadian dollar average exchange rate to assist in understanding our financial results.

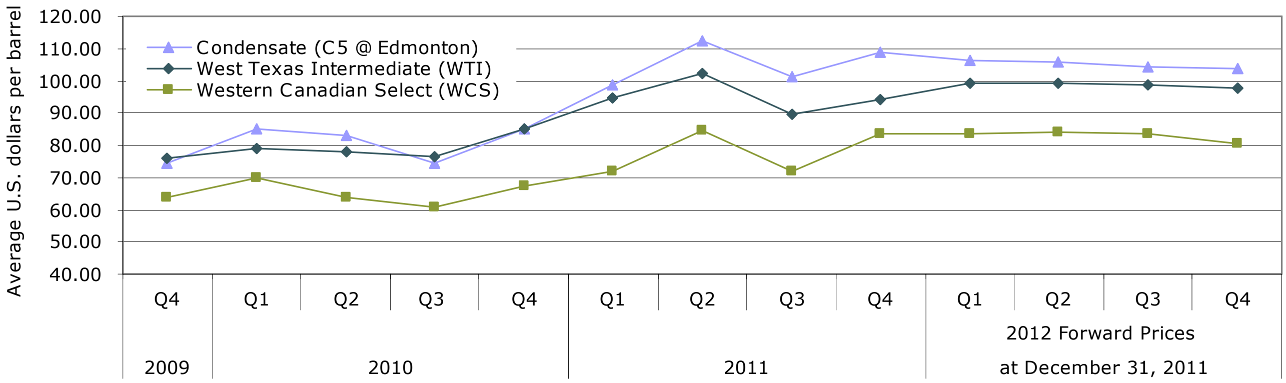
Selected Benchmark Prices and Exchange Rates

	2011	**Q4**	**Q3**	**Q2**	**Q1**	2010	Q4	Q3	Q2	Q1	2009
Crude Oil Prices *(US$/bbl)*											
West Texas Intermediate (WTI)											
Average	**95.11**	**94.06**	**89.54**	**102.34**	**94.60**	79.61	85.24	76.21	78.05	78.88	62.09
End of period	**98.83**	**98.83**	**79.20**	**95.42**	**106.72**	91.38	91.38	79.97	75.63	83.45	79.36
Western Canadian Select (WCS)											
Average	**77.96**	**83.58**	**71.92**	**84.70**	**71.74**	65.38	67.12	60.56	63.96	69.84	52.43
End of period	**84.37**	**84.37**	**69.38**	**75.32**	**91.37**	72.87	72.87	64.97	61.38	70.25	71.84
Average Differential WTI-WCS	**17.15**	**10.48**	**17.62**	**17.64**	**22.86**	14.23	18.12	15.65	14.09	9.04	9.66
Average Condensate (C5 @ Edmonton)	**105.34**	**108.74**	**101.48**	**112.33**	**98.90**	81.91	85.24	74.53	82.87	84.98	61.35
Average Differential WTI-Condensate (premium)/discount	**(10.23)**	**(14.68)**	**(11.94)**	**(9.99)**	**(4.30)**	(2.30)	-	1.68	(4.82)	(6.10)	0.74
Refining Margin 3-2-1 Average Crack Spreads ***(US$/bbl)***											
Chicago	**24.55**	**19.23**	**33.35**	**29.00**	**16.62**	9.33	9.25	10.34	11.60	6.11	8.54
Midwest Combined (Group 3)	**25.26**	**20.75**	**34.04**	**27.19**	**19.04**	9.48	9.12	10.60	11.38	6.82	8.09
Natural Gas Average Prices											
AECO *($/GJ)*	**3.48**	**3.29**	**3.53**	**3.54**	**3.58**	3.91	3.39	3.52	3.66	5.08	3.92
NYMEX *(US$/MMBtu)*	**4.04**	**3.55**	**4.19**	**4.31**	**4.11**	4.39	3.80	4.38	4.09	5.30	3.99
Basis Differential NYMEX-AECO *(US$/MMBtu)*	**0.31**	**0.17**	**0.34**	**0.42**	**0.29**	0.40	0.28	0.78	0.32	0.19	0.40
U.S./Canadian Dollar Exchange Rate											
Average	**1.012**	**0.978**	**1.020**	**1.033**	**1.015**	0.971	0.987	0.962	0.973	0.961	0.876

Crude Oil Benchmarks

WTI is an important benchmark for Canadian crude oil since it reflects onshore North American prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. In 2011, the volatility in the price of WTI was mainly due to the economic conditions of the European Union and the Libyan geopolitical conflict. At their peak in April 2011, WTI prices rose to over US$110.00 per barrel, primarily due to the loss of Libyan supply to the global market. With the resolution of the Libyan conflict, production from the country resumed at the end of the third quarter and is expected to gradually increase in 2012. Concern over the economic health and solvency of several countries within the European Union as well as inland U.S. crude oil market congestion at the end of September dropped WTI to under US$80.00 per barrel, its lowest point in 2011. In the fourth quarter of 2011, WTI improved and ended the year at US$98.83 per barrel on optimism of a strengthening U.S. economy and the announcement of the Seaway Pipeline reversal which more than offset the continued economic concerns in the European Union and OPEC's announcement to increase its 2012 production ceiling. The 2011 average price of WTI also benefited from increased Asian demand, primarily from China.

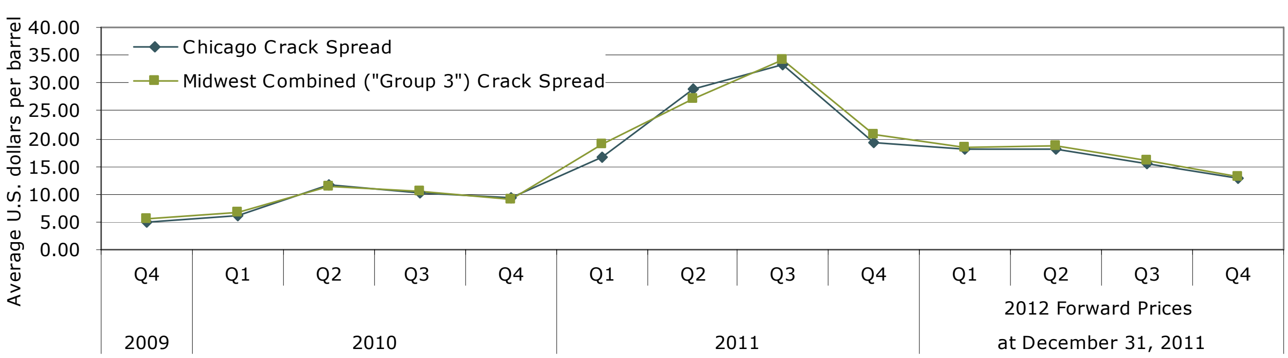
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is usually traded at a discount to the light oil benchmark, WTI. In 2011, the average WTI-WCS differential was impacted by pipeline restrictions in the first quarter which widened the average differential to over US$22.00 per barrel. These pipeline restrictions were resolved and new delivery capacity to Cushing, Oklahoma was added in the second quarter which helped to narrow the average WTI-WCS differential to under US$18.00 per barrel for the second and third quarters. In the fourth quarter, the WTI-WCS differential further narrowed to under US$11.00 per barrel due to overall stronger refining industry utilizations and increased demand for heavy crude oil partly due to advanced purchases for the CORE project at our Wood River Refinery. When compared to 2010, the average WTI-WCS differential widened as increased production of Canadian heavy crude oil supply and pipeline outages were only partially offset by increased coking capacity and refining industry utilization.



Blending condensate with bitumen enables our bitumen and heavy oil production to be transported. Our blending ratios range from 10 percent to 30 percent. The cost of condensate purchases impacts our revenues and our transportation and blending costs. The WTI-Condensate differential is the benchmark price of condensate relative to the price of WTI. The differentials for WTI-WCS and WTI-Condensate are independent of one another and tend not to move in tandem. Throughout 2011, WTI discounts to offshore light crudes increased and condensate premiums to WTI grew since the marginal barrel of condensate in Alberta markets was sourced from markets tied to global, rather than inland U.S. prices, and do not include an embedded inland U.S. discount included in the WTI benchmark price. However, in the fourth quarter of the 2011, the WTI discount to offshore light crude oils began to decrease with the announcement of the planned flow reversal of crude oil on the Seaway Pipeline in the middle of 2012. This planned flow reversal will supply crude oil to refineries on the U.S. Gulf Coast from the Cushing, Oklahoma hub. With the planned access to Gulf of Mexico markets, WTI prices strengthened in relation to offshore light oil benchmarks.

Refining 3-2-1 Crack Spread Benchmarks

The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel. Average crack spreads in the U.S. inland Chicago and Group 3 markets improved significantly from the same periods in 2010, benefiting from inland crude oil discounts and refined product prices that continued to be tied to global market prices which increased substantially in 2011. In the fourth quarter of 2011, crack spreads decreased compared to the previous quarter with the announcement that the flow of crude oil on the Seaway Pipeline will be reversed in the middle of 2012, increasing the price of crude oil feedstocks and narrowing the differential to global market prices. The Seaway Pipeline currently moves crude oil from the Gulf of Mexico to Cushing, Oklahoma. When reversed, it will help reduce surplus crude oil supply in the Cushing market by supplying heavy crude oil to the U.S. Gulf Coast refineries.



Benchmark crack spreads are a simplified view of the market based on last-in, first-out accounting, and reflect the current month WTI price as the crude oil feedstock price. Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and purchased product costs based on first-in, first-out accounting.

Other Benchmarks

Natural gas prices remained low during 2011. The low prices reflect the continued strong growth in supply from liquids-rich natural gas basins and the slow response of demand to lower natural gas prices. We do not expect prices to improve significantly in 2012 as demand growth is not expected to respond quickly enough to absorb the current supply surplus.

During 2011, the Canadian dollar strengthened relative to the U.S. dollar. An increase in the value of the Canadian dollar compared to the U.S. dollar has a negative impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a strengthened Canadian dollar reduces our reported results, although a stronger Canadian dollar reduces our current period's refining capital investment.

FINANCIAL INFORMATION

In 2011 we began reporting our financial results in accordance with IFRS. In accordance with IFRS 1, our transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been re-presented in accordance with IFRS. The 2009 financial information contained within this MD&A has been prepared following previous GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding our IFRS accounting policies can be found in the Accounting Policies and Estimates section of this MD&A as well as in the notes to the Consolidated Financial Statements.

SELECTED CONSOLIDATED FINANCIAL RESULTS

($ millions, except per share amounts)	2011	2011 vs 2010	2010	2010 vs 2009	2009 *(Prepared following previous GAAP)*
Revenues [1]	**15,696**	**24%**	12,641	15%	11,031
Operating Cash Flow [2]	**3,862**	**30%**	2,981	-29%	4,189
Cash Flow [2]	**3,276**	**36%**	2,412	-15%	2,845
- per share – diluted [3]	**4.32**	**35%**	3.20	-16%	3.79
Operating Earnings [2]	**1,239**	**55%**	799	-48%	1,522
- per share – diluted [3]	**1.64**	**55%**	1.06	-48%	2.03
Net Earnings	**1,478**	**37%**	1,081	32%	818
- per share – basic [3]	**1.96**	**36%**	1.44	32%	1.09
- per share – diluted [3]	**1.95**	**36%**	1.43	31%	1.09
Total Assets	**22,194**	**12%**	19,840	-9%	21,755
Total Long-Term Debt	**3,527**	**3%**	3,432	-6%	3,656
Other Long-Term Obligations	**5,873**	**7%**	5,503	-15%	6,507
Capital Investment [4]	**2,723**	**29%**	2,115	-2%	2,162
Cash Dividends [5]	**603**		601		159
- per share [5]	**0.80**		0.80		US$0.20

[1] The 2009 revenue component of realized and unrealized financial hedging net gains of $486 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.
[2] Financial measure without standardized meaning as prescribed by IFRS ("non-GAAP") and defined within this MD&A.
[3] Any per share amounts prior to December 1, 2009 have been calculated using Encana Corporation's ("Encana") common share balances based on the Arrangement which is further explained in the Advisory.
[4] Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.
[5] The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

REVENUES VARIANCE

($ millions)	Years Ended December 31, 2011 vs 2010	2010 vs 2009 [1]
Beginning period	$ 12,641	$ 11,031
Increase (decrease) due to:		
Oil Sands	584	428
Conventional	9	(110)
Refining and Marketing	2,397	1,306
Corporate and Eliminations	65	(14)
Ending period	**$ 15,696**	$ 12,641

[1] The 2009 revenue component of realized and unrealized financial hedging gains of $486 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Oil Sands revenues for 2011 increased primarily due to higher average crude oil sales prices, increased crude oil production, as well as higher condensate prices.

Conventional revenues increased slightly in 2011 as higher average crude oil sales prices and light and medium crude oil production were almost completely offset by decreased natural gas average sales prices and expected declines in natural gas production.

Refining and Marketing revenues in 2011 increased primarily due to improved refined product prices and volumes as well as higher revenues related to operational third party sales undertaken by the marketing group.

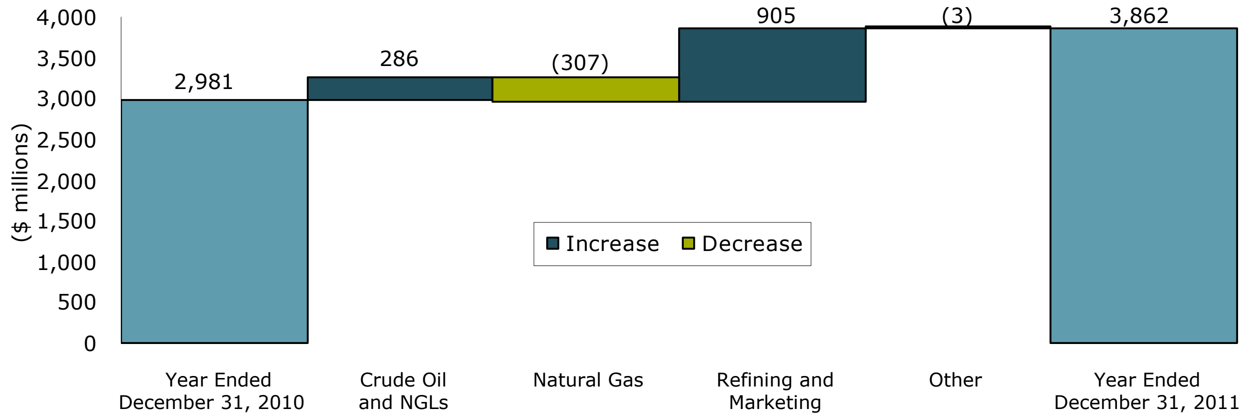
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

OPERATING CASH FLOW

($ millions)	2011	2010	2009 *(Prepared following previous GAAP)*
Oil Sands			
Crude Oil and NGLs	**$ 1,210**	$ 1,047	$ 1,002
Natural Gas	**52**	77	181
Other	**6**	7	(2)
Conventional			
Crude Oil and NGLs	**881**	758	753
Natural Gas	**725**	1,007	1,880
Other	**7**	9	7
Refining and Marketing	**981**	76	368
Operating Cash Flow	**$ 3,862**	$ 2,981	$ 4,189

Operating cash flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets and improves the comparability of our underlying financial performance between years. Operating cash flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less losses on risk management activities. Operating cash flow excludes unrealized gains and losses on risk management activities, which are included in the Corporate and Eliminations segment.

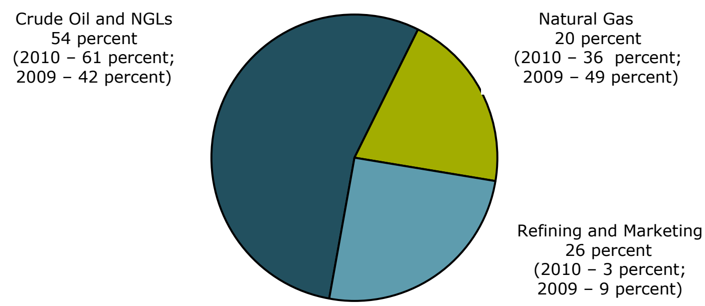
Operating Cash Flow Variance for the Year Ended December 31, 2011 compared to December 31, 2010



Overall, operating cash flow in 2011 increased $881 million primarily due to an increase of $905 million from Refining and Marketing as a result of improved refining margins. Operating cash flow from crude oil and NGLs increased $286 million due to an increase in average sales prices and sales volumes. The $307 million reduction from natural gas was due to decreased volumes, partly due to the divestiture of non-core natural gas properties at the end of the third quarter in 2010 and decreased average sales prices.

Operating Cash Flow of $3,862 million for the Year Ended December 31, 2011

The percentage of our operating cash flow generated from Refining and Marketing increased substantially in 2011 primarily due to improved refining margins. Crude oil and NGLs generated $2,091 million of operating cash flow in 2011 (2010 - $1,805 million; 2009 - $1,755 million), an increase of $286 million, from 2010. Despite this increase, the percentage of operating cash flow from crude oil and NGLs decreased to approximately 54 percent. The natural gas percentage of operating cash flow decreased from 2010 with the expected declines in our production and reduced sales prices.



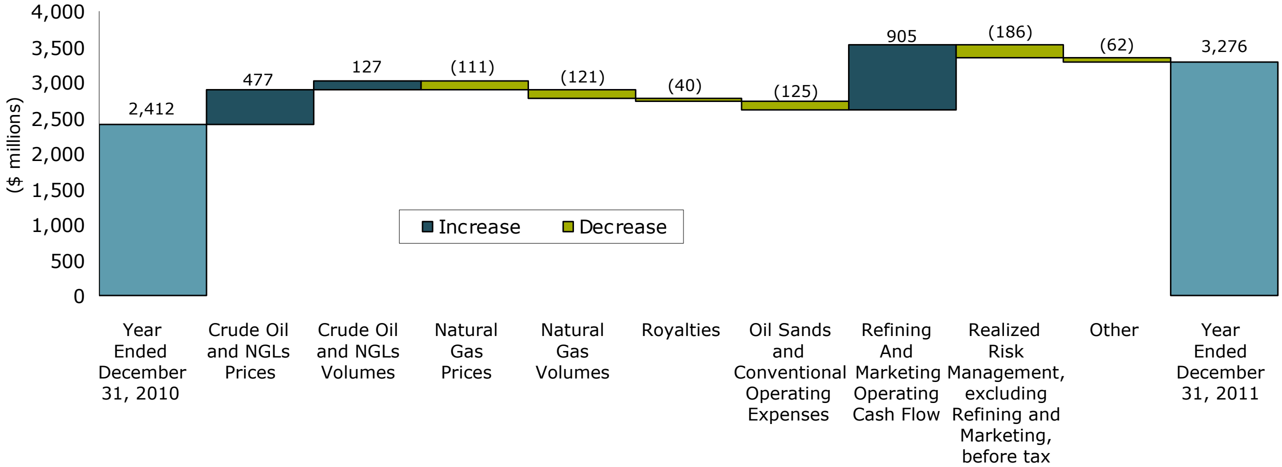
Additional details explaining the changes in operating cash flow can be found in the Reportable Segments section of this MD&A.

CASH FLOW

($ millions)	2011	2010	2009 (Prepared following previous GAAP)
Cash From Operating Activities	$ 3,273	$ 2,591	$ 3,039
(Add back) deduct:			
Net change in other assets and liabilities	(82)	(55)	(26)
Net change in non-cash working capital	79	234	220
Cash Flow	$ 3,276	$ 2,412	$ 2,845

Cash flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Cash flow is commonly used in the oil and gas industry to assist in measuring a company’s ability to finance its capital programs and meet its financial obligations.

Cash Flow Variance for the Year Ended December 31, 2011 compared to December 31, 2010



In 2011 our cash flow increased $864 million primarily due to:

- A significant increase in operating cash flow from Refining and Marketing of $905 million, mainly due to improved refining margins;
- A 16 percent increase in the average sales price of crude oil and NGLs to $72.84 per barrel;
- A four percent increase in our crude oil and NGLs sales volumes consistent with increased production primarily from Christina Lake, Foster Creek and conventional light and medium crude oil; and
- Lower interest expense with a stronger average Canadian dollar in 2011 decreasing interest on our U.S. dollar denominated long-term debt and partnership contribution payable as well as decreased interest on our partnership contribution payable as principal repayments are made quarterly.

The increases in our cash flow for 2011 were partially offset by:

- Realized risk management gains before tax, excluding Refining and Marketing, of $82 million compared to gains of $268 million in 2010;
- Increased operating expenses, primarily from crude oil and NGLs production, with additional personnel at Foster Creek, Christina Lake and Pelican Lake, increased repairs and maintenance and scheduled turnarounds activity, higher electricity costs and increased production from Bakken and Lower Shaunavon areas where production has been predominantly from single well batteries and resulted in increased trucking, fluid hauling and equipment rentals;
- Natural gas production declining 11 percent, as a result of the divestiture of non-core properties in 2010, lower capital investment and expected natural declines;
- An 11 percent decrease in the average natural gas sales price to $3.65 per Mcf;
- A $59 million increase in current income tax expense, excluding current tax on divestitures, as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010;
- Realized foreign exchange losses of $68 million in 2011 compared to losses of $18 million in 2010 primarily on the quarterly settlements of the partnership contribution receivable; and
- An increase in royalties of $40 million primarily as a result of the higher Canadian dollar WTI prices used to calculate royalty rates and improved crude oil production partially offset by decreased natural gas production and receiving approval from the ADOE to include all previous capital investment for Foster Creek expansion phases F, G and H as part our existing Foster Creek royalty calculation resulting in a one-time reduction of approximately $65 million.

OPERATING EARNINGS

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Net Earnings	**$ 1,478**	$ 1,081	$ 818
(Add back) deduct:			
Unrealized risk management gains (losses), after-tax [(1)]	**134**	34	(494)
Non-operating foreign exchange gains (losses), after-tax [(2)]	**14**	153	(210)
Gain (loss) on divestiture of assets, after-tax	**91**	83	-
Gain on bargain purchase, after-tax	**-**	12	-
Operating Earnings	**$ 1,239**	$ 799	$ 1,522

(1) The unrealized risk management gains (losses), after-tax includes the reversal of unrealized gains (losses) recognized in prior periods.
(2) After-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the partnership contribution receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

Operating earnings is a non-GAAP measure defined as net earnings excluding the after-tax gain (loss) on discontinuance; after-tax gain on bargain purchase; after-tax effect of unrealized risk management gains (losses) on derivative instruments; after-tax gains (losses) on non-operating foreign exchange; after-tax effect of gains (losses) on divestiture of assets; and the effect of changes in statutory income tax rates. We believe that these non-operating items reduce the comparability of our underlying financial performance between periods. The above reconciliation of operating earnings has been prepared to provide information that is more comparable between periods.

The increase in operating earnings in 2011 is consistent with higher operating cash flow partially offset by higher general and administrative costs and income tax expense (excluding deferred tax on the gains and losses on unrealized risk management, non-operating foreign exchange and divestitures).

NET EARNINGS VARIANCE

($ millions)	
Net Earnings for the Year Ended December 31, 2010	$ 1,081
Increase (decrease) due to:	
Operating Cash Flow	881
Corporate and Eliminations	
Unrealized risk management gains (losses), after-tax	100
Unrealized foreign exchange gains (losses)	(27)
Gain (loss) on divestiture of assets	(9)
Expenses [(1)]	(86)
Depreciation, depletion and amortization	7
Exploration expense	3
Income taxes, excluding income taxes on unrealized risk management gains (losses)	(472)
Net Earnings for the Year Ended December 31, 2011	**$ 1,478**

(1) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, other (income) loss, net and Corporate and Eliminations operating expenses.

In 2011, our net earnings increased $397 million compared to 2010. The factors discussed above that increased our operating cash flow in 2011 also increased our net earnings. Other significant factors that impacted our net earnings in 2011 include:

- Unrealized risk management gains, after-tax, of $134 million, compared to gains of $34 million in 2010;
- Unrealized foreign exchange gains of $42 million compared to gains of $69 million in 2010 consistent with the decrease of the Canadian dollar exchange rate at December 31, 2011 on the translation of our U.S. dollar long-term debt partially offset by the translation of our U.S. dollar denominated partnership contribution receivable;
- An increase of $49 million for general and administrative expenses primarily due to increases in salaries and benefits and office support costs, as well as higher long-term incentive costs;
- Lower gains on the divestiture of assets, as we recognized gains of $107 million in 2011 compared to gains of $116 million in 2010 on the sale of non-core properties;
- A decrease of $7 million in Depletion, Depreciation and Amortization ("DD&A") expense as increased crude oil production and a $45 million impairment of a refining asset were partially offset by the addition of proved reserves at Foster Creek at the end of 2010 and decreased natural gas production; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, increasing to $683 million, compared to $211 million in 2010.

NET CAPITAL INVESTMENT

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Oil Sands	$ 1,415	$ 857	$ 629
Conventional	788	526	466
Refining and Marketing	393	656	1,033
Corporate	127	76	34
Capital Investment	2,723	2,115	2,162
Acquisitions	71	86	3
Divestitures	(173)	(307)	(222)
Net Capital Investment [1]	$ 2,621	$ 1,894	$ 1,943

[1] Includes expenditures on PP&E and E&E. For purposes of managing our capital program, we do not differentiate between PP&E and E&E expenditures, and therefore we have not split our capital investment within this MD&A.

Oil Sands capital investment in 2011 included site construction, facility engineering and procurement spending at Foster Creek for expansion phases F, G and H. At Christina Lake, capital investment included site preparation and facility construction for expansion phases D, E and F and completion of phase C construction. Pelican Lake capital investment included infill drilling for polymer flooding and facility expansion and maintenance. We also drilled 480 gross stratigraphic test wells in 2011, of which 440 were drilled during the first quarter of 2011 which was our largest program to date. The results of these stratigraphic test wells will be used to support the expansion and development of our Oil Sands projects.

Conventional capital investment in 2011 was primarily focused on the development of our crude oil properties including drilling, completion and facilities work in the Lower Shaunavon and Bakken areas. Our Conventional capital investment increased compared to 2010 and was on plan for 2011 despite flooding in the second quarter of 2011 in southern Saskatchewan which restricted access to our properties.

Refining and Marketing capital investment in 2011 was primarily focused on construction of the CORE project at the Wood River Refinery. Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Corporate capital investment in 2011 was for tenant improvements and information technology costs.

Acquisitions and Divestitures

The acquisitions in 2011 were primarily related to purchases of exploration and evaluation lands located contiguous to our existing core areas. Divestitures included the sale of marine terminal facilities in Kitimat, British Columbia and certain undeveloped land.

CAPITAL INVESTMENT DECISIONS

The table below reflects the outcome of our capital allocation process since the inception of Cenovus. It is important to understand that our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third, for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow.

($ millions)	**2011**	2010	2009 *(Prepared following previous GAAP)*
Cash Flow	**$ 3,276**	$ 2,412	$ 2,845
Capital Investment (Committed and Growth)	**2,723**	2,115	2,162
Free Cash Flow [1]	**553**	297	683
Dividends paid [2]	**603**	601	159
	$ (50)	$ (304)	$ 524

[1] Free cash flow is a non-GAAP measure defined as cash flow less capital investment.
[2] The 2009 dividend represents the fourth quarter dividend determined in connection with the Arrangement based on carve-out earnings and cash flow.

RISK MANAGEMENT ACTIVITIES

Our risk management strategy is to use financial instruments to protect and provide certainty on a portion of our cash flows. The financial instrument agreements are recorded at the date of the financial statements based on mark-to-market accounting. Changes in mark-to-market gains or losses on these financial instruments affect our net earnings until these contracts are settled and are the result of volatility in the forward commodity prices and changes in the balance of unsettled contracts. This program increases cash flow certainty and historically has provided a net financial benefit, however, there is no certainty that we will continue to derive such benefits in the future.

The realized risk management amounts in the tables below impact our operating cash flow, cash flow, operating earnings and net earnings. Unrealized risk management amounts are a non-cash item included in net earnings and affects the Corporate and Eliminations segment's financial results. Additional information regarding financial instruments can be found in the notes to the Consolidated Financial Statements.

Financial Impact of Risk Management Activities

	2011			2010			2009		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	**$ (135)**	**$ 106**	**$ (29)**	$ (17)	$ (92)	$ (109)	$ 49	$ (102)	$ (53)
Natural Gas	**210**	**38**	**248**	289	152	441	1,105	(566)	539
Refining	**(14)**	**7**	**(7)**	10	(8)	2	(34)	(10)	(44)
Power	**7**	**29**	**36**	(4)	(6)	(10)	(4)	(20)	(24)
Gains (Losses) on Risk Management	**68**	**180**	**248**	278	46	324	1,116	(698)	418
Income Tax Expense(Recovery)	**17**	**46**	**63**	79	12	91	312	(204)	108
Gains (Losses) on Risk Management, after-tax	**$ 51**	**$ 134**	**$ 185**	$ 199	$ 34	$ 233	$ 804	$ (494)	$ 310

In 2011, our risk management strategy resulted in realized losses on our crude oil financial instruments and realized gains on our natural gas financial instruments. These results are consistent with our contract prices compared to the current business environment of low benchmark natural gas prices and increased WTI benchmark crude oil prices which ended 2011 at a higher price than in 2010. We also recognized unrealized gains on our crude oil and natural gas financial instruments as a result of the decrease in forward commodity prices at the end of 2011 compared to our contract prices. Details of contract volumes and prices are found in the notes to the Consolidated Financial Statements.

RESULTS OF OPERATIONS

CRUDE OIL and NGLs PRODUCTION VOLUMES

(barrels per day)	2011	2011 vs 2010	2010	2010 vs 2009	2009
Oil Sands					
Foster Creek	**54,868**	**7%**	51,147	36%	37,725
Christina Lake	**11,665**	**48%**	7,898	18%	6,698
Pelican Lake	**20,424**	**-11%**	22,966	-8%	24,870
Senlac	**-**	**-**	-	-	3,057
Conventional					
Heavy Oil	**15,657**	**-6%**	16,659	-7%	17,888
Light & Medium Oil	**30,524**	**4%**	29,346	-3%	30,394
NGLs [1]	**1,101**	**-6%**	1,171	-3%	1,206
	134,239	**4%**	129,187	6%	121,838

[1] NGLs include condensate volumes.

In 2011, our crude oil and NGLs production increased four percent primarily due to higher production at Christina Lake, Foster Creek and Conventional light and medium crude oil. These increases were partially offset by the temporary curtailment of production at Pelican Lake from wild fires which restricted pipeline transportation in the second quarter and the scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake. Conventional production was impacted by natural declines at our heavy oil operations, flooding and wet weather in southern Saskatchewan and Alberta in the second quarter, poor winter weather in the first quarter and the divestiture of non-core assets in the second quarter of 2010. Our average crude oil and NGLs production for December 2011 was 150,977 barrels per day, an increase of 22,971 barrels per day or 18 percent from December 2010 and was primarily due to increased production from Christina Lake and Conventional light and medium oil. Further information on the changes in our crude oil and NGLs production can be found in the Reportable Segments section of this MD&A.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	2011	2011 vs 2010	2010	2010 vs 2009	2009
Conventional	**619**	**-11%**	694	-11%	784
Oil Sands	**37**	**-14%**	43	-19%	53
	656	**-11%**	737	-12%	837

The decrease in our 2011 natural gas production compared to 2010 was due to our strategic decision to restrict capital spending on our natural gas assets over the prior two years in favour of increasing investment in crude oil projects. In 2010, we also divested of non-core natural gas properties which had produced approximately four percent of our 2010 production. Weather related issues, including extreme cold in the first quarter and wet weather in the second quarter of 2011, also reduced our natural gas production. While year over year natural gas production decreased, 2011 natural gas production remained consistent during the year despite low levels of capital investment. Further information on the changes in our natural gas production can be found in the Reportable Segments section of this MD&A.

OPERATING NETBACKS

	2011		2010		2009	
	Crude Oil & NGLs	**Natural Gas**	Crude Oil & NGLs	Natural Gas	Crude Oil & NGLs	Natural Gas
	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)	($/bbl)	($/Mcf)
					(Prepared following previous GAAP)	
Price [1]	**$ 72.84**	**$ 3.65**	$ 62.96	$ 4.09	$ 57.14	$ 4.15
Royalties	**9.84**	**0.06**	9.33	0.07	5.62	0.08
Transportation and blending [1]	**2.76**	**0.15**	1.88	0.17	1.60	0.15
Operating expenses	**13.47**	**1.10**	11.74	0.95	10.67	0.86
Production and mineral taxes	**0.56**	**0.04**	0.62	0.02	0.65	0.05
Netback excluding Realized Risk Management	**46.21**	**2.30**	39.39	2.88	38.60	3.01
Realized Risk Management Gains (Losses)	**(2.79)**	**0.87**	(0.36)	1.07	1.10	3.63
Netback including Realized Risk Management	**$ 43.42**	**$ 3.17**	$ 39.03	$ 3.95	$ 39.70	$ 6.64

[1] The crude oil and NGLs price and transportation and blending costs exclude $24.91 per barrel (2010 - $20.36 per barrel; 2009 - $14.55 per barrel) of condensate purchases which is blended with heavy crude oil.

In 2011, our average netback for crude oil and NGLs, excluding realized risk management gains and losses, increased by $6.82 per barrel primarily due to increased sales prices consistent with higher benchmark prices. Increased benchmark pricing also increased royalties. The increased sales prices were partially offset by higher operating expenses and transportation and blending costs. The increase in operating expenses was primarily due to higher staffing levels and increased repairs and maintenance activity at Foster Creek, Christina Lake and Pelican Lake. Transportation costs increased as a result of pursuing new markets for our increasing crude oil production.

Our average netback for natural gas, excluding realized risk management gains and losses, decreased $0.58 per Mcf primarily due to lower sales prices and increased operating expenses.

Further discussion on the items included in our operating netbacks is included in the Reportable Segments section of this MD&A. Further information on our risk management strategy can be found in the Risk Management section of this MD&A and in the notes to the Consolidated Financial Statements.

REPORTABLE SEGMENTS

OIL SANDS

In northeast Alberta, we are a 50 percent partner in the Foster Creek and Christina Lake oil sands projects and also produce heavy oil from our wholly owned Pelican Lake operations. We have several new resource plays in the early stages of assessment, including Narrows Lake, Grand Rapids and Telephone Lake. The Oil Sands assets also include the Athabasca natural gas property from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant factors that impacted our Oil Sands segment in 2011 include:

- A 270 million barrel increase in proved reserve volumes primarily due to receiving regulatory approval for Christina Lake phases E, F and G;
- Foster Creek adding 56 million barrels of proved reserves with the positive results from delineation drilling, improved recovery from wells using our Wedge Well™ technology and improved steam chamber recovery;
- Achieving first production at Christina Lake phase C in August ahead of schedule. Capital expenditures for the entire phase were below budget. Net production at Christina Lake was approximately 23,000 barrels per day at the end of the year;
- Implementing steam dilation as part of Christina Lake phase C start up which accelerated the initial start-up of production from well pairs;
- Foster Creek average production increasing seven percent to 54,868 barrels per day and Christina Lake production increasing 48 percent to an average of 11,665 barrels per day;
- Completing scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake on time and on budget;
- Receiving ADOE approval for the inclusion of Foster Creek expansion phases F, G and H capital investment from inception to June 30, 2011 as part of our existing Foster Creek royalty calculation resulting in a one-time reduction of about $65 million in our royalty expense;
- Receiving approval from the ERCB for Christina Lake expansion phases E, F and G;
- Receiving partner approval for Foster Creek expansion phases F, G and H and Christina Lake phase E;
- Successfully completing a large winter stratigraphic test well program with 480 gross wells drilled mainly in the first quarter to further progress our Oil Sands projects and address potential Pelican Lake lease expiries;
- Our best estimate bitumen contingent resources increasing by 2.1 billion barrels or approximately 34 percent primarily on transfers from prospective resources based on the results of our 2011 stratigraphic test well program;
- Pelican Lake production decreasing 11 percent to an average of 20,424 barrels per day, primarily due to the temporary curtailment of production due to wild fires in the area which decreased production by approximately 500 barrels per day, a scheduled turnaround which reduced production by approximately 300 barrels per day and expected natural declines;
- Applying for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities and increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G; and
- Updating our strategic plan which targets:
    - Increasing our expected total gross production capacity from Foster Creek phases F, G and H and future phases by 55,000 to 75,000,barrels per day from the original estimate;
    - Accelerating the timelines for first production at Foster Creek phases G and H by approximately one year;
    - Expected first production at Christina Lake phase D and phase E in the fourth quarters of 2012 and 2013 respectively, approximately six months earlier than initially planned. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design; and
    - Increasing expected production from Pelican Lake to 55,000 barrels per day by the end of 2016.

OIL SANDS - CRUDE OIL

Financial Results

($ millions)	2011	2010	2009 [1]
			(Prepared following previous GAAP)
Gross Sales	$ 3,217	$ 2,610	$ 2,008
Less: Royalties	282	276	129
Revenues	2,935	2,334	1,879
Expenses			
Transportation and blending	1,229	934	626
Operating	409	339	297
Production and mineral tax	-	-	1
(Gains) losses on risk management	87	14	(47)
Operating Cash Flow	1,210	1,047	1,002
Capital Investment	1,401	850	629
Operating Cash Flow in Excess (Deficient) of Related Capital Investment	$ (191)	$ 197	$ 373

[1] In 2009, realized financial hedging gains in revenue of $48 million and realized financial hedging losses in operating costs of $1 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Revenues Variances

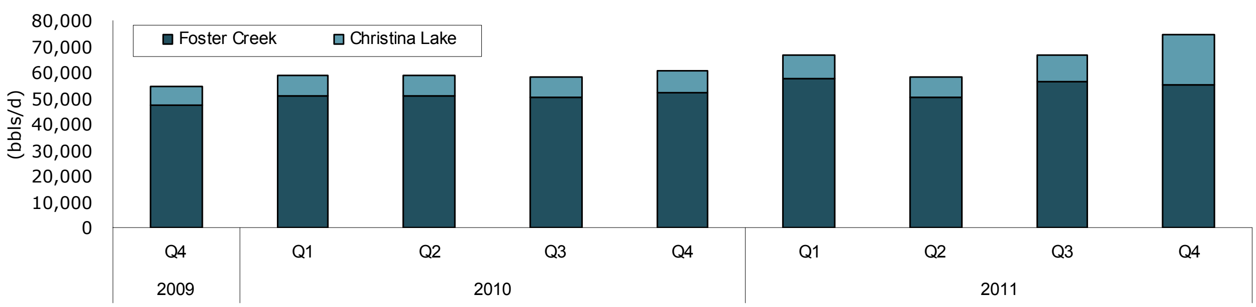
($ millions)	Year Ended December 31, 2010	Price	Volume	Royalties	Condensate[1]	Year Ended December 31, 2011
	$ 2,334	253	97	(6)	257	$ 2,935

[1] Revenues include the value of condensate sold as bitumen blend. Condensate costs are recorded in transportation and blending expense.

Production Volumes

Crude oil (barrels per day)	2011	2011 vs 2010	2010	2010 vs 2009	2009
Foster Creek	54,868	7%	51,147	36%	37,725
Christina Lake	11,665	48%	7,898	18%	6,698
Subtotal	66,533	13%	59,045	33%	44,423
Pelican Lake	20,424	-11%	22,966	-8%	24,870
Senlac	-	-	-	-	3,057
	86,957	6%	82,011	13%	72,350

Foster Creek and Christina Lake Production Volumes by Quarter



In 2011, our average crude oil sales price increased 14 percent to $67.99 per barrel compared to 2010, consistent with the increase in the WCS benchmark price partially offset by higher condensate costs and the strengthening of the Canadian dollar.

Foster Creek production increased seven percent primarily as a result of improved plant efficiency and well performance due to less downtime as well as improvements in the steam to oil ratio, partially offset by the scheduled turnaround completed in the second quarter of 2011. The 48 percent increase in production at Christina Lake was the result of the start up of phase C in the third quarter of 2011, two well pairs which came on production in the fourth quarter of 2010 and four wells (which use our Wedge Well™ technology) which came on production in 2011, partially offset by a scheduled turnaround completed in the second quarter of 2011. The decline in our Pelican Lake production was primarily due to the temporary curtailment of production in the second quarter of 2011 due to wild fires in the area which decreased production by approximately 500 barrels per day for the year and a scheduled turnaround in the third quarter of 2011 which reduced production by approximately 300 barrels per day for the year. Production at Pelican Lake was also reduced by expected natural production declines and pipeline apportionments partially offset by higher production due to polymer injection activities in 2011.

Royalty calculations for our oil sands projects are a function of the Canadian dollar WTI benchmark price and volume for pre-payout royalties (Christina Lake) and price, volume, allowed operating and capital costs for post-payout projects (Foster Creek and Pelican Lake). Royalties increased $6 million in 2011 primarily due to increased production at Christina Lake and Foster Creek, higher Canadian dollar WTI prices and Foster Creek being in post–payout for a full year after achieving payout in the first quarter of 2010. Royalties would have been about $65 million higher had we not received ADOE approval for the inclusion of Foster Creek expansion phases F, G and H capital investment from inception to June 30, 2011 as part of our existing Foster Creek royalty calculation. Also partially offsetting these increases were higher capital investment and decreased production at Pelican Lake. The effective royalty rates for 2011 were 16.8 percent at Foster Creek (2010 – 16.2 percent; 2009 – 2.7 percent), 5.2 percent at Christina Lake (2010 – 3.9 percent; 2009 – 2.3 percent) and 11.5 percent at Pelican Lake (2010 – 21.1 percent; 2009 – 20.1 percent).

Transportation and blending costs increased $295 million in 2011. The condensate (blending) portion of the increase was $257 million and was the result of increases in the average cost of condensate and volumes required due to increased production at Foster Creek and Christina Lake. Transportation costs increased $38 million primarily as a result of higher production volumes, increased transportation charges in the first quarter to access available markets to avoid shut-in of volumes due to pipeline restrictions and additional transportation allowing us to access an offshore market in the fourth quarter.

Our 2011 operating costs were primarily for staffing, workovers, repairs and maintenance; Foster Creek and Christina Lake fuel costs; and chemical usage at Pelican Lake and Foster Creek. In total, operating costs increased $70 million in 2011 due to scheduled turnarounds at Foster Creek, Christina Lake and Pelican Lake, higher staffing levels, increased repairs and maintenance expense and higher long-term incentive expense, partially offset by decreased trucking and chemical costs.

Risk management activities resulted in realized losses of $87 million (2010 – losses of $14 million; 2009 – gains of $47 million) consistent with the 2011 average benchmark prices exceeding our 2011 contract prices.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operations in Athabasca and other minor properties. Primarily as a result of expected natural declines, our natural gas production decreased to 37 MMcf per day in 2011 (2010 – 43 MMcf per day; 2009 – 53 MMcf per day). As a result of the decreased production and lower natural gas prices, operating cash flow declined to $52 million for 2011 (2010 - $77 million; 2009 - $181 million).

OIL SANDS - CAPITAL INVESTMENT

($ millions)	2011	2010	2009 (Prepared following previous GAAP)
Foster Creek	$ 429	$ 277	$ 262
Christina Lake	472	346	224
Subtotal	901	623	486
Pelican Lake	317	104	72
New Resource Plays	180	113	17
Other [1]	17	17	54
Capital Investment [2]	$ 1,415	$ 857	$ 629

(1) Includes Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment in 2011 was primarily focused on the development of the expansion phases at Foster Creek and Christina Lake, facility expansion and infill drilling activities related to our Pelican Lake polymer flood and the drilling of stratigraphic test wells to support the development of our Oil Sands projects.

As compared to 2010, Foster Creek capital investment for 2011 increased primarily as a result of drilling 118 gross stratigraphic test wells in 2011 (2010 – 82 wells; 2009 – 65 wells) and higher spending on site construction, facility engineering and procurement for expansion phases F, G and H. Foster Creek capital investment also included maintenance capital on our producing phases and infrastructure spending.

Christina Lake capital investment was higher in 2011 compared to 2010 due primarily to the phase D, E and F expansions, including site preparation and facility construction, maintenance capital on producing phases and drilling 63 gross stratigraphic test wells (2010 – 24 wells; 2009 – 28 wells). We expect to increase gross production capacity to approximately 138,000 barrels per day with the completion of phases D and E. First production at phase D is expected in the fourth quarter of 2012 and first production at phase E is expected in the fourth quarter of 2013, both phases are now expected to commence production approximately six months earlier than initially scheduled. This acceleration results from a combination of capital execution efficiencies at both the Nisku module yard and at the construction site, as well as the application of new start up technologies and well design.

Pelican Lake capital investment for 2011 was primarily related to infill drilling to progress the polymer flood, drilling of stratigraphic test wells, facilities expansions and maintenance capital. Facilities spending was focused on expanding fluid capacity at Pelican Lake through additions and upgrades to our boiler units and emulsion pipelines.

(gross production wells drilled [1])	2011	2010	2009
Foster Creek	21	37	42
Christina Lake	19	32	-
Subtotal	40	69	42
Pelican Lake	31	12	5
Grand Rapids	-	1	-
Other	3	-	11
	74	82	58

(1) Includes wells drilled using our Wedge Well™ technology

Capital investment in new resource plays in 2011 was mainly related to the drilling of stratigraphic test wells, completion of seismic programs to support future oil sands projects and the Grand Rapids pilot project. First oil from the Grand Rapids pilot project was achieved in the third quarter of 2011. Results to date are as expected and will give us a better understanding of the performance of SAGD in the Grand Rapids formation.

Stratigraphic Test Wells

Consistent with our strategy to unlock the value of our resource base, we completed our largest ever stratigraphic test well program in the first quarter of 2011 and began our next stratigraphic test well drilling program in the fourth quarter. The stratigraphic test wells drilled at Foster Creek and Christina Lake are to support the next phases of expansion, while the other stratigraphic test wells have been drilled to continue to gather data on the quality of our projects and to support regulatory applications for project approval. We also drilled a number of wells at Pelican Lake to address potential lease expiries. To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed during the winter months, which typically occurs at the end of the fourth quarter and at the beginning of the first quarter.

Our 2011 stratigraphic test well program provided the primary basis for the 2.1 billion barrel increase to our best estimate bitumen contingent resources as results from the program caused prospective resources to be reclassified as contingent resources.

(gross stratigraphic test wells drilled)	**2011**	2010	2009
Foster Creek	**118**	82	65
Christina Lake	**63**	24	28
Subtotal	**181**	106	93
Pelican Lake	**57**	-	-
Narrows Lake	**47**	39	-
Grand Rapids	**59**	71	17
Telephone Lake	**40**	26	-
Borealis	**44**	-	-
Other	**52**	17	-
	480	259	110

CONVENTIONAL

Our Conventional operations include the development and production of crude oil, natural gas and NGLs in Alberta and Saskatchewan. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of products produced. The reliability of these properties to deliver consistent production and operating cash flow is important to the funding of our future crude oil growth. We plan to assess the potential of new crude oil projects on our existing properties and new regions, especially tight oil opportunities.

Significant factors that impacted our Conventional segment in 2011 include:

- Generating operating cash flow in excess of capital investment from our Conventional natural gas assets of $623 million;
- Average crude oil production from our Lower Shaunavon area more than doubling to 2,041 barrels per day with capital spending focusing on drilling, completions and facilities;
- Flooding which resulted in restricted access and shut-in production at our Bakken, Lower Shaunavon and Weyburn operations in the second quarter which reduced our production by approximately 1,400 barrels per day;
- Effectively managing the expected natural declines in our natural gas assets resulting in an absolute year over year production decline of 11 percent and a seven percent decrease, excluding the 2010 dispositions;
- Shifting our capital investment focus from natural gas to crude oil where we increased crude oil capital investment by 89 percent and drilled an additional 145 crude oil wells compared to 2010; and
- Updating our strategic plan which targets production of 65,000 to 75,000 barrels per day from our conventional crude oil operations in Saskatchewan and southern Alberta by the end of 2016 as well as assessing the potential of new crude oil projects on our existing properties and in new regions with a focus on tight oil opportunities.

CONVENTIONAL - CRUDE OIL and NGLs

Financial Results

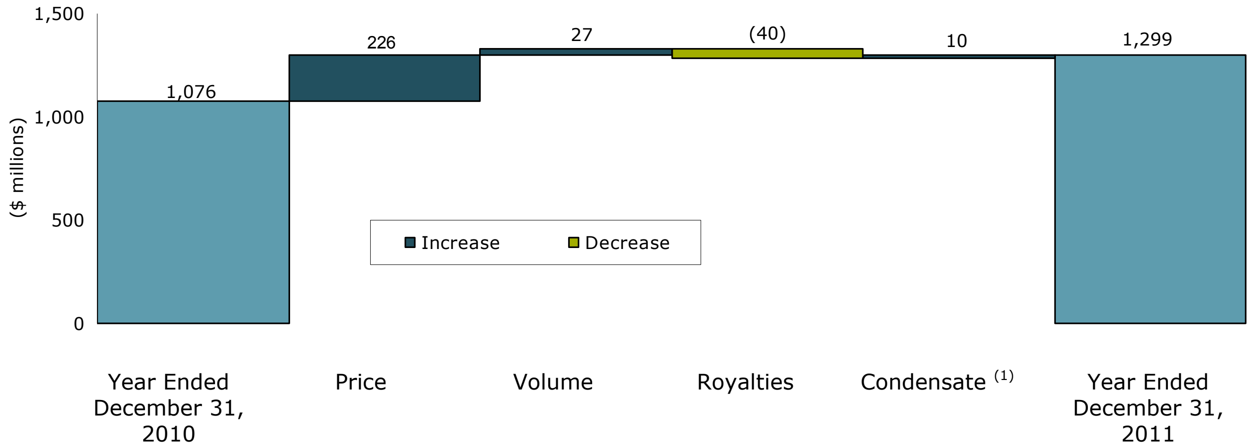
($ millions)	2011	2010	2009 [1]
			(Prepared following previous GAAP)
Gross Sales	**$ 1,492**	$ 1,229	$ 1,161
Less: Royalties	**193**	153	119
Revenues	**1,299**	1,076	1,042
Expenses			
Transportation and blending	**104**	86	87
Operating	**244**	199	172
Production and mineral taxes	**27**	28	28
(Gains) losses on risk management	**43**	5	2
Operating Cash Flow	**881**	758	753
Capital Investment	**686**	363	223
Operating Cash Flow in Excess of Related Capital Investment	**$ 195**	$ 395	$ 530

[1] In 2009, realized financial hedging losses in operating costs of $2 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Production Volumes

(barrels per day)	2011	2011 vs 2010	2010	2010 vs 2009	2009
Heavy Oil					
Alberta	**15,657**	**-6%**	16,659	-7%	17,888
Light and Medium Oil					
Alberta	**10,763**	**-1%**	10,854	-9%	11,959
Saskatchewan	**19,761**	**7%**	18,492	-%	18,435
NGLs	**1,101**	**-6%**	1,171	-3%	1,206
	47,282	**-%**	47,176	-5%	49,488

Revenues Variance for the Years Ended December 31, 2011 compared to December 31, 2010



[1] Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense.

Our average crude oil and NGLs sales price increased 19 percent to $81.41 per barrel, consistent with the increase in crude oil benchmark prices.

Our sales and production volumes increased slightly, primarily because of higher light and medium crude oil production from our Bakken and Lower Shaunavon areas. These increases were mostly offset by the effects of cold weather in Alberta in early 2011, wet weather in Alberta and Saskatchewan in the middle of 2011, natural declines and the 2010 divestiture of non-core properties.

Royalties increased by $40 million primarily as a result of increased crude oil prices which resulted in an effective crude oil royalty rate of 14.2 percent (2010 – 13.3 percent; 2009 – 11.4 percent).

Transportation and blending costs increased $18 million. The condensate portion of the increase was $10 million as increases in the average cost of condensate were partially offset by a decrease in the volume required for blending consistent with the decline in heavy oil production. Transportation costs increased $8 million primarily due to a higher proportion of volumes being shipped subject to spot pipeline tolls.

Our primary operating costs components were electricity, repairs and maintenance, workover activity and staff costs. Operating costs increased $45 million for 2011 primarily due to higher electricity costs, increased repairs and maintenance and workover activity, higher salaries and benefits, increased trucking and waste handling costs as well as increased equipment rentals.

Risk Management activities resulted in realized losses of $43 million (2010 - losses of $5 million; 2009 – losses of $2 million) consistent with the 2011 average benchmark prices exceeding our 2011 contract prices.

Operating cash flow from Conventional crude oil and NGLs in excess of capital investment decreased $200 million in 2011 primarily due to a $323 million increase in capital investment, focused on drilling, completions and facilities work in Alberta and Saskatchewan, partially offset by higher crude oil and NGLs prices and increased light and medium crude oil production.

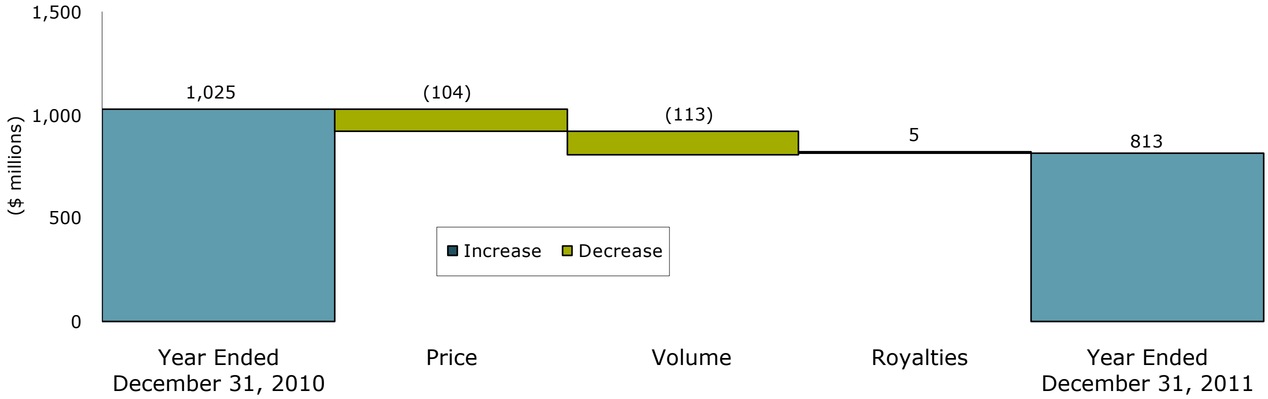
CONVENTIONAL - NATURAL GAS

Financial Results

($ millions)	**2011**	2010	2009 [1] *(Prepared following previous GAAP)*
Gross Sales	**$ 825**	$ 1,042	$ 1,189
Less: Royalties	**12**	17	19
Revenues	**813**	1,025	1,170
Expenses			
Transportation and blending	**34**	44	45
Operating	**240**	231	236
Production and mineral taxes	**9**	6	15
(Gains) losses on risk management	**(195)**	(263)	(1,006)
Operating Cash Flow	**725**	1,007	1,880
Capital Investment	**102**	163	243
Operating Cash Flow in Excess of Related Capital Investment	**$ 623**	$ 844	$ 1,637

[1] In 2009, realized financial hedging gains in revenue of $1,007 million and realized financial hedging losses in operating costs of $1 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

Revenues Variance for the Years Ended December 31, 2011 compared to December 31, 2010



Our natural gas revenues and operating cash flow were lower in 2011 primarily due to lower production and average sales prices. The decline in our average sales price is consistent with the change in the benchmark AECO price. The cumulative impact of restricted natural gas capital spending over the last two years, the 2010 divestiture of non-core properties which had produced approximately four percent of our 2010 production, extreme cold in the first quarter and wet weather in the second quarter resulted in a decrease in natural gas production volumes to 619 MMcf per day for 2011 (2010 – 694 MMcf per day; 2009 – 784 MMcf per day). While year over year production was down, production within 2011 remained relatively flat with low levels of capital investment.

Royalties decreased $5 million in 2011 due to lower production and prices. The average 2011 royalty rate was 1.5 percent (2010 – 1.7 percent; 2009 – 1.6 percent).

Transportation costs decreased $10 million due to lower production volumes.

Our primary operating expense components include property taxes and lease costs, repairs and maintenance, staffing costs and electricity. Operating expenses increased $9 million in 2011 as higher expenses associated with electricity, increased workover activity and long-term incentives were partially offset by reduced operations due to divestitures in 2010 and lower production volumes.

Risk management activities resulted in realized gains in 2011 of $195 million (2010 – gains of $263 million; 2009 – gains of $1,006 million) consistent with our 2011 contract price exceeding the 2011 average benchmark price.

Operating cash flow from Conventional natural gas in excess of capital investment decreased $221 million primarily due to lower production volumes and average sales prices decreasing operating cash flow partially offset by a $61 million reduction in capital investment.

CONVENTIONAL - CAPITAL INVESTMENT

($ millions)	2011	2010	2009 *(Prepared following previous GAAP)*
Crude Oil	**$ 686**	$ 363	$ 223
Natural Gas	**102**	163	243
Capital Investment [1]	**$ 788**	$ 526	$ 466

[1] Includes expenditures on PP&E and E&E assets.

Capital investment in our Conventional segment was focused on our crude oil development opportunities and high value natural gas opportunities such as CBM recompletions. Increased crude oil capital investment in Saskatchewan was focused on drilling and facility work at Weyburn and appraisal projects, drilling, completions and facilities work in the Lower Shaunavon and Bakken areas. Alberta crude oil capital investment was focused on drilling activities. Despite the impact of flooding in southern Saskatchewan in the second quarter we were able to complete our 2011 planned capital investment.

The following table details our Conventional drilling activity. The increase in crude oil wells reflects the development of our Alberta properties and the Lower Shaunavon and Bakken areas in Saskatchewan. Well recompletions are mostly related to Alberta coal bed methane development.

(net wells)	2011	2010	2009
Crude Oil	**325**	180	105
Natural Gas	**65**	495	502
Recompletions	**1,122**	1,194	855
Stratigraphic Test Wells	**11**	9	5

REFINING AND MARKETING

This segment includes the results of our refining operations in the U.S. that are jointly owned with and operated by ConocoPhillips. Accordingly, reported amounts for refining are affected by the U.S./Canadian dollar exchange rate. This segment's results also include the marketing of third party purchases and sales of product, undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Significant factors related to our Refining and Marketing segment in 2011 include:

- Increased operating cash flow of $905 million primarily due to improved refining margins, consistent with higher benchmark crack spreads, and higher refinery utilization;
- Completed coker construction and start up activities of the CORE project in the fourth quarter of 2011; and
- Our refineries operating at 89 percent of capacity producing 419 thousand barrels per day of refined products.

Financial Results

($ millions)	2011	2010	2009 [1] *(Prepared following previous GAAP)*
Revenues	**$ 10,625**	$ 8,228	$ 6,922
Purchased product	**9,149**	7,674	5,986
Gross margin	**1,476**	554	936
Expenses			
Operating expenses	**481**	488	534
(Gain) loss on risk management	**14**	(10)	34
Operating Cash Flow	**981**	76	368
Capital Investment	**393**	656	1,033
Operating Cash Flow in Excess (Deficient) of Capital Investment	**$ 588**	$ (580)	$ (665)

[1] In 2009, realized financial hedging losses in purchased product of $34 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

The gross margin for Refining and Marketing increased $922 million for 2011 primarily due to the significant improvement in refined product prices which more than offset higher purchased product costs compared to 2010. Refined product prices continue to be tied to global market prices which increased substantially in 2011. Purchased product costs, which are accounted for on a first-in, first-out basis, reflected the benefit of discounted heavy crude oil as well as discounts to U.S. inland crude oil for much of 2011. Both the heavy and inland crude oil discounts that benefited our refining financial results throughout 2011, reduced substantially midway through the fourth quarter with the announced plan to increase the transportation of crude oil to the U.S. gulf coast reducing the surplus that had generated the discounts. The benefit to our refining results of discounted purchased product prices demonstrates the effectiveness of our objective to economically integrate our heavy oil production. Gross margins realized in 2011 also reflected the impact of higher utilization when compared to 2010.

Operating costs, consisting mainly of labour, maintenance, utilities and supplies, decreased by $7 million in 2011 primarily due to the impact of a stronger Canadian dollar and reduced scheduled turnarounds costs.

Overall, this segment's operating cash flow, which is mainly generated by our refining operations, increased $905 million in 2011 primarily due to the higher refining gross margins. This contrasts with 2010 which was affected by weaker refined product prices, refinery optimization and scheduled turnarounds. Capital investment decreased by $263 million in 2011 as CORE project construction neared completion.

REFINERY OPERATIONS [1]

	2011	2010	2009
Crude oil capacity *(Mbbls/d)*	**452**	452	452
Crude oil runs *(Mbbls/d)*	**401**	386	394
Crude utilization *(percent)*	**89**	86	87
Refined products *(Mbbls/d)*	**419**	405	417

[1] Represents 100 percent of the Wood River and Borger refinery operations.

On a 100 percent basis, our refineries had a capacity of approximately 452,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine up to 145,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our objective of economically integrating our heavy oil production. Refining capacity increases attributable to the CORE project at the Wood River Refinery, including expanded coking and heavy oil processing capacities will be reflected in 2012 operations as plant test runs proceed.

Crude utilization in 2011 improved as the 2010 utilization levels were affected by refinery optimization activities undertaken in conjunction with market conditions at that time and scheduled turnarounds.

REFINING AND MARKETING - CAPITAL INVESTMENT

($ millions)	2011	2010	2009 *(Prepared following previous GAAP)*
Wood River Refinery	**$ 346**	$ 568	$ 944
Borger Refinery	**45**	87	88
Marketing	**2**	1	1
Capital Investment	**$ 393**	$ 656	$ 1,033

Our refining capital investment in 2011 continued to focus on the CORE project at the Wood River Refinery. In 2011, of the $346 million capital expenditures at the Wood River Refinery, $243 million were related to the CORE project. In the fourth quarter of 2011 we completed the CORE project coker construction. Total CORE capital expenditures were approximately US$3.8 billion (US$1.9 billion net to Cenovus), or about 10 percent higher than originally budgeted.

The balance of the 2011 capital investment at the Wood River and Borger refineries was related to refining reliability and maintenance projects, clean fuels and other emission reduction environmental initiatives.

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	2011	2010	2009 [1] *(Prepared following previous GAAP)*
Revenues	**$ (59)**	$ (124)	$ (110)
Expenses ((add)/deduct)			
Purchased product	**(59)**	(123)	(110)
Operating	**(1)**	(3)	-
(Gains) losses on risk management	**(180)**	(46)	698
	$ 181	$ 48	$ 698

[1] The 2009 revenue and operating cost components of unrealized financial hedging losses, $668 million and $30 million respectively, have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.

The Corporate and Eliminations segment includes intersegment eliminations that relate to transactions that have been recorded at transfer prices based on current market prices as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and unrealized mark-to-market gains and losses on long-term power purchase contracts.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities made up of the following:

($ millions)	2011	2010	2009 [1]
			(Prepared following previous GAAP)
General and administrative	**$ 295**	$ 246	$ 211
Finance costs	**447**	498	476
Interest income	**(124)**	(144)	(187)
Foreign exchange (gain) loss, net	**26**	(51)	304
(Gain) loss on divestiture of assets	**(107)**	(116)	(2)
Other (income) loss, net	**4**	(13)	-
	$ 541	$ 420	$ 802

[1] 2009 interest, net has been reclassified to interest income and finance costs and accretion of asset retirement obligations has been reclassified to finance costs to conform to the current year's IFRS presentation.

General and administrative expenses increased $49 million in 2011. Increased staffing levels in 2011 to support our growth resulted in higher salaries and benefits, higher long-term incentive expense and increased office support costs.

Finance costs include interest expense on our long-term debt and short-term borrowings and U.S. dollar denominated partnership contribution payable, as well as the unwinding of discount on decommissioning liabilities. In 2011, our finance costs were $51 million lower than 2010 primarily as a result of a stronger average Canadian dollar in 2011 reducing our interest expense on our U.S. dollar denominated long-term debt as well as decreasing interest being incurred on the partnership contribution payable as principal payments are made quarterly. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated partnership contribution payable, for 2011 was 5.5 percent (2010 – 5.8 percent; 2009 – 5.5 percent).

Interest income primarily includes interest earned on our U.S. dollar denominated partnership contribution receivable. Interest income for 2011 decreased by $20 million from 2010 mainly as a result of decreasing interest being earned on the partnership contribution receivable as the balance is being collected combined with a stronger average Canadian dollar.

In 2011, we reported net foreign exchange losses of $26 million (2010 - gains of $51 million; 2009 – losses of $304 million), which includes unrealized gains of $42 million (2010 – unrealized gains of $69 million; 2009 – unrealized losses of $327 million) and realized losses of $68 million (2010 – realized losses of $18 million; 2009 – realized gains of $23 million). The decrease of the Canadian dollar exchange rate at December 31, 2011 from 2010 led to unrealized losses on our U.S. dollar denominated long-term debt partially offset by net gains on our U.S. dollar denominated partnership contribution receivable.

A net gain of $107 million was recorded on the divestiture of assets in 2011 (2010 – $116 million; 2009 - $2 million) mainly due to the sale of marine terminal facilities as well as certain non-core assets.

DEPRECIATION, DEPLETION and AMORTIZATION

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Oil Sands	**$ 347**	$ 375	
Conventional	**778**	799	
Upstream	**1,125**	1,174	$ 1,250
Refining and Marketing [1]	**130**	96	232
Corporate and Eliminations	**40**	32	45
	$ 1,295	$ 1,302	$ 1,527

[1] On the January 1, 2010 transition to IFRS we elected to measure the carrying value of our refineries at their then estimated fair value resulting in a permanent $2.6 billion reduction to their carrying value and decreasing DD&A expense in 2010 compared to 2009.

For 2011, Oil Sands DD&A decreased $28 million as higher sales volumes at Foster Creek and Christina Lake were offset by lower sales volumes at Pelican Lake and lower Oil Sands DD&A rates. The lower Oil Sands DD&A rates for 2011 were mostly due to the significant addition of proved reserves at Foster Creek at the end of 2010.

DD&A in the Conventional segment decreased $21 million in 2011 primarily due to the decrease in natural gas production volumes and the disposition of non-core assets.

Refining and Marketing DD&A increased $34 million of which $45 million was due to the impairment of a catalytic cracking unit at the Wood River Refinery which will not be used in future operations. Refining and Marketing DD&A in 2010 included a loss on impairment of a redundant processing unit at the Borger Refinery of $14 million. Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, office furniture and leasehold improvements.

INCOME TAX EXPENSE

($ millions)	2011	2010	2009 (Prepared following previous GAAP)
Current tax	$ **154**	$ 82	$ 934
Deferred tax	**575**	141	(590)
	$ **729**	$ 223	$ 344

When comparing 2011 to 2010, our current tax expense increased primarily due to the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception.

When comparing 2011 to 2010, our deferred tax expense increased primarily due to increased income from our Refining and Marketing segment which attract income tax at the higher U.S. tax rates and higher unrealized risk management gains.

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions, except percent amounts)	2011	2010	2009 (Prepared following previous GAAP)
Earnings before income tax	$ **2,207**	$ 1,304	$ 1,162
Canadian statutory rate	**26.7%**	28.2%	29.2%
Expected income tax	**589**	368	339
Effect of taxes resulting from:			
Foreign tax rate differential	**78**	(22)	3
Non-deductible stock-based compensation	**18**	34	-
Multi-jurisdictional financing	**(50)**	(93)	(134)
Foreign exchange gains (losses) not included in net earnings	**(9)**	28	58
Non-taxable capital (gains) losses	**(9)**	(13)	30
Capital loss	**26**	(107)	-
Adjustments arising from prior year tax filings	**31**	26	(16)
Other	**55**	2	64
	729	223	344
Effective tax rate	**33.0%**	17.1%	29.6%

The Canadian statutory tax rate decreased to 26.7 percent in 2011 from 28.2 percent in 2010 as a result of tax legislation enacted in 2007.

The increase in our effective tax rate in 2011 is primarily due to a significant increase in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction and lower benefits of multi-jurisdictional financing. The effective tax rate for 2010 was unusually low because of a tax benefit recorded in respect of losses incurred in the U.S. in 2010.

Our effective tax rate in any year is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. The effective tax rate differs from the statutory tax rate as it takes into consideration permanent differences, adjustments for changes in tax rates and other tax legislation, variation in the estimate of reserves and the differences between the provision and the actual amounts subsequently reported on the tax returns. Permanent differences include:
- The non-taxable portion of Canadian capital gains and losses;
- Multi-jurisdictional financing;
- Non-deductible stock-based compensation;
- Recognition of net capital losses; and
- Taxable foreign exchange gains not included in net earnings.

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate.

QUARTERLY INFORMATION

($ millions, except per share amounts)	**Q4 2011**	**Q3 2011**	**Q2 2011**	**Q1 2011**	Q4 2010	Q3 2010	Q2 2010	Q1 2010	Q4 2009
									(Prepared following previous GAAP)
Production Volumes									
Crude Oil and NGLs	**144,273**	**133,496**	**121,762**	**137,355**	129,593	128,067	128,566	130,549	129,315
Natural Gas	**660**	**656**	**654**	**652**	688	738	751	775	797
Revenues [1]	**4,329**	**3,858**	**4,009**	**3,500**	3,363	2,962	3,094	3,222	2,970
Operating Cash Flow [2]	**1,019**	**945**	**1,064**	**834**	815	661	665	840	954
Cash Flow [2]	**851**	**793**	**939**	**693**	645	509	537	721	235
- per share – diluted [3]	**1.12**	**1.05**	**1.24**	**0.91**	0.85	0.68	0.71	0.96	0.31
Operating Earnings [2]	**332**	**303**	**395**	**209**	147	156	143	353	169
- per share – diluted [3]	**0.44**	**0.40**	**0.52**	**0.28**	0.19	0.21	0.19	0.47	0.23
Net Earnings	**266**	**510**	**655**	**47**	78	295	183	525	42
- per share – basic [3]	**0.35**	**0.68**	**0.87**	**0.06**	0.10	0.39	0.24	0.70	0.06
- per share – diluted [3]	**0.35**	**0.67**	**0.86**	**0.06**	0.10	0.39	0.24	0.70	0.06
Capital Investment [4]	**903**	**631**	**476**	**713**	701	479	444	491	507
Cash Dividends [5]	**151**	**150**	**151**	**151**	151	150	150	150	159
- per share [5]	**0.20**	**0.20**	**0.20**	**0.20**	0.20	0.20	0.20	0.20	US$0.20

(1) In the fourth quarter of 2009, realized and unrealized financial hedging gains from revenue of $35 million have been reclassified to (gain) loss on risk management to conform to the current year's IFRS presentation.
(2) Non-GAAP measures defined within this MD&A.
(3) Any per share amounts prior to December 1, 2009 have been calculated using Encana's common share balances based on the Arrangement which is further explained in the Advisory.
(4) Includes expenditures on PP&E and E&E assets.
(5) The fourth quarter 2009 dividend reflected an amount determined in connection with the Arrangement based on carve-out earnings and cash flow.

The improvements in our operational and financial results in the fourth quarter of 2011 demonstrated the dedication of our teams throughout the year. In the fourth quarter, we completed the coker construction and start up activities of the CORE project construction at the Wood River Refinery, more than doubled production from Christina Lake and Lower Shaunavon compared to the fourth quarter of 2010 and completed our 2011 capital program despite the impacts of wet weather in the second and third quarters.

In the fourth quarter of 2011, coker construction and start up activities of the CORE project at the Wood River Refinery were completed. The initial CORE design included increasing nameplate refining capacity by 50,000 barrels per day and doubling heavy crude oil refining capacity to approximately 240,000 barrels per day, enhancing our ability to integrate our growing bitumen production. Total CORE project construction costs are within 10 percent of its original budget.

Our crude oil and NGLs fourth quarter production increased by 11 percent compared to the same period in 2010 due to increased production from Christina Lake, Foster Creek and at our Conventional light and medium crude oil properties. Partially offsetting these increases was the expected natural declines at Pelican Lake and at our Conventional heavy oil properties. The increase in production at Christina Lake was mainly due to the start of production at phase C in the third quarter of 2011.

We applied for an amendment to the existing Christina Lake regulatory approval to add cogeneration facilities to Christina Lake, increasing expected total gross production capacity by 10,000 barrels per day at each of phase F and phase G.

Natural gas production in the fourth quarter of 2011 was 660 MMcf per day, a decrease of four percent from 2010 due to expected declines in production from limited capital investment.

Capital investment in the fourth quarter of 2011 was $903 million, an increase of $202 million from 2010. The fourth quarter was extremely busy with activity at three phases at Foster Creek, three phases at Christina Lake and our drilling and completions programs across the other areas.

Operating cash flow increased $204 million in the fourth quarter of 2011 primarily due to crude oil and NGLs increasing $157 million due to higher average sales prices and sales volumes. Refining and Marketing operating cash flow increased $113 million attributable to improved refining margins. The $64 million decrease in operating cash flow from natural gas was consistent with lower production volumes and average sales prices.

In the fourth quarter of 2011 our cash flow increased $206 million compared to 2010 primarily due to:
- A 28 percent increase in the average sales price of crude oil and NGLs to $80.50 per barrel;
- An increase in operating cash flow from Refining and Marketing of $113 million, mainly due to improved refining margins; and
- An increase in our crude oil and NGLs sales volumes consistent with the 11 percent increase in production volumes primarily related to Christina Lake, conventional light and medium crude oil and Foster Creek.

The increases in our cash flow in the fourth quarter of 2011 were partially offset by:
- Increased operating expenses, primarily from crude oil and NGLs production, due to higher staffing levels at Foster Creek, Christina Lake and Pelican Lake, increased trucking and fluid hauling costs with increased production at Bakken and Lower Shaunavon and higher electricity and workover costs;
- Realized risk management gains before tax, excluding Refining and Marketing, of $29 million compared to gains of $79 million in 2010;
- An increase in royalties of $43 million mainly as a result of higher crude oil production and increases to the Canadian dollar equivalent WTI price used to calculate certain royalty rates;
- A $29 million increase in current income tax expense, excluding current tax on divestitures, as a result of the substantial utilization in 2010 of certain Canadian tax pools acquired at our inception which lowered current income tax expense for 2010;
- A six percent decrease in the average natural gas sales price to $3.35 per Mcf; and
- Natural gas production declining four percent (28 MMcf per day), as a result of lower capital investment and expected natural declines.

In the fourth quarter of 2011, our net earnings increased $188 million compared to 2010. The factors discussed above that increased our operating cash flow in the fourth quarter of 2011 also increased our net earnings. Other significant factors that impacted our 2011 fourth quarter net earnings include:
- Unrealized risk management losses, after-tax, of $180 million, compared to losses of $197 million in the fourth quarter of 2010;
- A gain of $104 million on the divesture of a non-core asset in the fourth quarter of 2011 compared to the fourth quarter of 2010 when we recognized a loss of $3 million;
- Increased DD&A expense of $59 million primarily due to a $45 million refining asset impairment in the fourth quarter of 2011; and
- Income tax expense, excluding the impact of unrealized risk management gains and losses, of $150 million, compared to $75 million in 2010.

OIL AND GAS RESERVES AND RESOURCES

As a Canadian issuer, we are subject to the reporting requirements of Canadian securities regulatory authorities, including the reporting of our reserves in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

Our reserves are primarily located in Alberta and Saskatchewan, Canada. We retained two independent qualified reserves evaluators ("IQREs"), McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and CBM reserves. McDaniel also evaluated 100 percent of our contingent and prospective bitumen resources.

The Reserves Committee of the Board, composed of independent directors, annually reviews the qualifications and selection of the IQREs, the procedures relating to the disclosure of information with respect to oil and gas activities and the procedures for providing information to the IQREs. The Reserves Committee meets independently with management and with each IQRE to determine whether any restrictions affect the ability of the IQRE to report on the reserves data without reservation, to review the reserves data and the report of the IQRE thereon, and to provide a recommendation on approval of the reserves and resources disclosure to the Board.

Highlights in 2011 include:

- Bitumen proved reserves increased approximately 26 percent and proved plus probable reserves increased approximately 16 percent;
    - Christina Lake added proved reserves of 270 million barrels while proved plus probable reserves increased by 213 million barrels. Increases at Christina Lake were primarily a result of receiving regulatory approval to expand the development area and from positive delineation results;
    - Foster Creek added proved reserves of 56 million barrels and proved plus probable reserves of 79 million barrels. Increases at Foster Creek were primarily due to positive revisions from delineation results, increased recovery from wells using our Wedge Well™ technology and improved steam chamber recovery;
- Heavy oil proved reserves increased approximately four percent and proved plus probable reserves increased approximately seven percent. These increases were primarily as a result of expanding polymer flood areas and the successful performance of those flood areas at Pelican Lake;
- Light and medium oil and NGLs proved and proved plus probable reserves each increased by approximately four percent, primarily as a result of expanding waterflood and carbon dioxide flood areas and the successful performance of those flood areas at Weyburn;
- Natural gas proved reserves declined approximately 13 percent and proved plus probable reserves declined approximately 11 percent due to extensions and technical revisions not offsetting production and due to the impacts of declined capital investment;
- Best estimate economic contingent resources increased 2.1 billion barrels or approximately 34 percent. This increase is primarily as a result of our significant stratigraphic test well drilling program successfully converting prospective resources to contingent resources and positive technical revisions to volumetric and recovery factor estimates;
- Best estimate prospective resources declined 2.3 billion barrels or approximately 19 percent, primarily as a result of the reclassification of prospective resources to contingent resources resulting from stratigraphic test well drilling.

The reserves and resources data is presented as at December 31, 2011 using McDaniel's January 1, 2012 forecast prices and costs and as at December 31, 2010 using McDaniel's January 1, 2011 forecast prices and costs. We hold significant fee title rights which generate production for our account from third parties leasing those lands. The before royalty volumes presented below do not include reserves associated with this production.

RESERVES AT DECEMBER 31

	Bitumen (MMbbls)		Heavy Oil (MMbbls)		Light & Medium Oil & NGLs (MMbbls)		Natural Gas & CBM (Bcf)	
Before Royalties	**2011**	2010	**2011**	2010	**2011**	2010	**2011**	2010
Proved	**1,455**	1,154	**175**	169	**115**	111	**1,203**	1,390
Probable	**490**	523	**109**	97	**51**	49	**391**	410
Proved plus Probable	**1,945**	1,677	**284**	266	**166**	160	**1,594**	1,800

RECONCILIATION OF PROVED RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2010	1,154	169	111	1,390
Extensions and Improved Recovery	256	16	13	50
Discoveries	-	-	-	-
Technical Revisions	69	2	1	29
Economic Factors	-	1	-	(28)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production	(24)	(13)	(10)	(238)
December 31, 2011	1,455	175	115	1,203
Year over year change	301	6	4	(187)
	26%	4%	4%	-13%

RECONCILIATION OF PROBABLE RESERVES

Before Royalties	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2010	523	97	49	410
Extensions and Improved Recovery	32	14	3	11
Discoveries	-	-	-	-
Technical Revisions	(65)	(2)	(1)	(27)
Economic Factors	-	-	-	(3)
Acquisitions	-	-	-	-
Dispositions	-	-	-	-
Production	-	-	-	-
December 31, 2011	490	109	51	391
Year over year change	(33)	12	2	(19)
	-6%	12%	4%	-5%

ECONOMIC CONTINGENT and PROSPECTIVE RESOURCES AT DECEMBER 31

Before Royalties	Bitumen (billions of barrels) 2011	2010
Economic contingent resources[(1)]		
Low Estimate	**6.0**	4.4
Best Estimate	**8.2**	6.1
High Estimate	**10.8**	8.0
Prospective resources[(1)(2)]		
Low Estimate	**5.7**	7.3
Best Estimate	**10.0**	12.3
High Estimate	**17.9**	21.7

(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and low, best and high estimate. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.
(2) There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources. Prospective resources are not screened for economic viability.

Contingent and prospective resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Existing SAGD projects that are producing from the McMurray-Wabiskaw formations are used as performance analogs at Foster Creek and Christina Lake. Other regional analogs are used for contingent and prospective resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property in the Pelican Lake Region, in the McMurray formation at the Telephone Lake property in the Borealis Region and in the Clearwater formation in the Foster Creek Region.

Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The Canadian Oil and Gas Evaluation Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. The contingencies applicable to our contingent resources are not categorized as economic. Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican.

At Foster Creek and Christina Lake we have economic contingent resources located outside the currently approved development project areas. Regulatory approval of development project area expansion is necessary to enable the reclassification of these economic contingent resources as reserves. The rate at which we submit applications for development area expansion is dependent on the rate of development drilling, which ties to an orderly development plan that maximizes utilization of steam generation facilities and ultimately optimizes production, capital utilization and value.

In the Borealis Region we have submitted an application for a development project at the Telephone Lake property which, if approved, would enable the reclassification of certain economic contingent resources in the area to reserves. Other areas in the Borealis Region require additional results from delineation drilling and seismic activity in order to submit regulatory applications for development projects. Stratigraphic test well drilling and seismic activity is continuing in these areas to bring them to project readiness. Currently, sufficient pipeline capacity is also considered a contingency.

In the Greater Pelican Region we submitted an application in the fourth quarter of 2011 for development project approval at the Grand Rapids property. Provided all regulatory requirements are met, we anticipate receiving regulatory approval in 2013. Pilot project work is underway to examine optimal development strategies.

We are systematically progressing our bitumen prospective resources to contingent resources and then to reserves, and ultimately to production. For example, approval for expansion of the Christina Lake development area resulted in the movement of some contingent resources to proved and probable reserves. Similarly, the stratigraphic test well program in the Borealis and Pelican Lake Regions moved some prospective resources to contingent resources. The overall reduction to prospective resources is the expected outcome of a successful stratigraphic test well program, which converts undiscovered resources to discovered resources.

Bitumen reserves and resources increased in part because of improvements in SAGD performance at our Foster Creek and Christina Lake properties resulting from improved operating performance and the use of wells drilled using our Wedge Well™ technology. Analysis of core data in the steamed portions of the reservoir has revealed that the efficiency of the SAGD process in extracting bitumen from the reservoir is greater than previously anticipated. We expect to continue to improve overall recovery from our bitumen assets as technology develops.

Information with respect to pricing as well as additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resource estimates, is contained in our Annual Information Form ("AIF") for the year ended December 31, 2011 (see the Additional Information section).

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2011	2010	2009
			(Prepared following previous GAAP)
Net cash from (used in)			
Operating activities	**$ 3,273**	$ 2,591	$ 3,039
Investing activities	**(2,530)**	(1,793)	(2,063)
Net cash provided (used) before Financing activities	**743**	798	976
Financing activities	**(558)**	(631)	(977)
Foreign exchange gains (losses) on cash and cash equivalents held in foreign currency	**10**	(22)	(32)
Increase (decrease) in cash and cash equivalents	**$ 195**	$ 145	$ (33)

OPERATING ACTIVITIES

Cash from operating activities increased $682 million in 2011 compared to 2010 mainly because of an $864 million increase in cash flow, which is discussed in the Financial Information section of this MD&A. Cash from operating activities is also impacted by the net change in non-cash working capital and the net change in other assets and liabilities.

Excluding risk management assets and liabilities and assets held for sale, we had working capital of $283 million at December 31, 2011 compared to $276 million at December 31, 2010. We anticipate that we will continue to meet our payment obligations.

INVESTING ACTIVITIES

Cash used for investing activities in 2011 increased $737 million from 2010. The increase is primarily due to higher capital expenditures, which increased by $591 million and decreased proceeds from divestiture of assets of $136 million. Capital expenditures are further discussed under Net Capital Investment within the Financial Information section and Capital Investment within the Reportable Segments sections of this MD&A.

FINANCING ACTIVITIES

In September 2011, we renegotiated our existing $2.5 billion committed bank credit facility, increasing the facility to $3.0 billion and extending the maturity date to November 30, 2015. In addition, the standby fees required to maintain the facility and the cost of future borrowings were reduced. We also have a commercial paper program which, together with the committed credit facility, may be used to manage our short-term cash requirements. At December 31, 2011, we had no short-term borrowings (2010 and 2009 – nil) in the form of commercial paper. We reserve capacity under our committed credit facility for amounts of commercial paper outstanding.

In addition, we have in place a Canadian debt shelf prospectus for $1.5 billion and a U.S. debt shelf prospectus for US$1.5 billion, the availability of which are dependent on market conditions. No notes have been issued under either prospectus. The Canadian debt shelf prospectus expires in July 2012 and the U.S. debt shelf prospectus in August 2012. It is our intention to renew both prospectuses prior to their expiration.

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment then to paying a meaningful dividend and then finally to growth capital. In 2011, we declared and paid quarterly dividends of $0.20 per share (2010 – $0.20 per share; 2009 – US$0.20 per share in the fourth quarter) for total dividend payments of $603 million (2010 - $601 million; 2009 - $159 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in 2011 decreased by $73 million from 2010. The decrease in 2011 was primarily due to $58 million of revolving long-term debt payments in 2010 compared to none in 2011 and higher proceeds on the issuance of common shares in 2011, which were as a result of stock option exercises. Our long-term debt was $3,527 million as at December 31, 2011 (2010 - $3,432 million; 2009 - $3,656 million). There are no payments of principal due until September 2014 ($814 million).

As at December 31, 2011, we are in compliance with all of the terms of our debt agreements.

FINANCIAL METRICS

	December 31,		
	2011	2010	2009
Debt to Capitalization	**27%**	29%	32% (1)
Debt to Adjusted EBITDA (times)	**1.0x**	1.3x	0.9x (2)

(1) The 2009 Debt to Capitalization ratio has been calculated as at January 1, 2010 on an IFRS basis.
(2) The 2009 Debt to Adjusted EBITDA ratio has been calculated on a previous GAAP basis.

In 2011, driven by strong operational results, our financial position has improved as measured by our debt to capitalization and debt to adjusted EBITDA metrics both of which are at or below the low end of our target ranges.

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capitalization and debt to adjusted EBITDA. We define our non-GAAP measure of debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the partnership contribution payable or receivable. We define our non-GAAP measure of capitalization as debt plus shareholders' equity. Trailing 12-month Adjusted EBITDA is a non-GAAP measure defined as earnings before finance costs, interest income, income tax expense, DD&A, exploration expense, unrealized gain (loss) on risk management, foreign exchange gains (losses), gain (loss) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position as measures of our overall financial strength.

In order to increase comparability of debt to adjusted EBITDA between periods and remove the non-cash component of risk management activities, we changed our definition of adjusted EBITDA in 2011 to exclude unrealized gains and losses on risk management activities. Adjusted EBITDA and the ratio of debt to adjusted EBITDA for 2010 and 2009 have been re-presented in a consistent manner. Our capital structure objectives and targets remain unchanged from previous periods.

We continue to target a debt to capitalization ratio of between 30 to 40 percent and a debt to adjusted EBITDA of between 1.0 to 2.0 times. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

OUTSTANDING SHARE DATA

Cenovus 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 at December 31, 2011, approximately 754.5 million common shares were outstanding (2010 – 752.7 million; 2009 – 751.3 million) and no preferred shares were outstanding. The increase in common shares in 2011 was the result of stock option exercises. No other issuance of common shares has occurred in 2011.

We have in place a Board approved dividend reinvestment plan ("DRIP"), which permits holders of common shares to automatically reinvest all or any portion of their cash dividends paid on their common shares in additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. For the years ended December 31, 2011 and 2010, common shares were purchased on the market to meet our DRIP requirements.

Long-term Incentive Plans

The Cenovus Stock Option Plan ("ESOP") permits our Board, from time to time, to grant to employees of Cenovus and its subsidiaries stock options to purchase our common shares. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted under the ESOP are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 expire after seven years.

Options granted prior to February 24, 2011 have an associated tandem share appreciation right ("TSAR"), which gives employees the right to elect to receive a cash payment equal to the excess of the market price of our common shares over the exercise period of their option in exchange for surrendering their option. A portion of the options have an additional vesting condition which is subject to the Company attaining prescribed performance relative to key pre-determined measures. The performance-based options that do not vest when eligible are forfeited. The exercise of an option as a TSAR for a cash payment does not result in the issuance of any additional common shares, thus having no dilutive effect.

Options granted on or after February 24, 2011 have associated net settlement rights ("NSR"). The NSRs, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of our common shares at the time of exercise over the exercise price of the option.

The TSARs and NSRs vest and expire under the same terms and conditions as the underlying options.

In accordance with the Arrangement, each Cenovus and Encana employee holding Encana options prior to the Arrangement received one Cenovus replacement option and one Encana replacement option for each original Encana option held. The terms and conditions of the Cenovus replacement options are similar to the terms and conditions of the original Encana options, which are also similar to the terms and conditions of Cenovus options. The original exercise price of the Encana options was apportioned to the Cenovus and Encana replacement options based on the one-day weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the Toronto Stock Exchange on December 2, 2009.

No further Cenovus replacement options will be granted to Encana employees. Encana is required to reimburse Cenovus in respect of cash payments made to Encana employees for Cenovus replacement options exercised as TSARs. Cenovus is required to reimburse Encana in respect of cash payments made to Cenovus employees for Encana replacement options exercised as TSARs. No further Encana replacement options will be granted to Cenovus employees.

The following is a summary of long-term incentives outstanding at year end:

	2011		2010		2009	
	Units[1]	Price[2]	Units[1]	Price[2]	Units[1]	Price[2]
TSARs						
- outstanding	**14,921**	**$ 28.12**	19,117	$ 27.75	16,455	$ 27.52
- exercisable	**8,874**	**$ 29.15**	7,734	$ 28.07	6,107	$ 25.68
NSRs						
- outstanding	**5,809**	**$ 36.95**	-	-	-	-
- exercisable	**1**	**$ 37.54**	-	-	-	-
Cenovus Replacement TSARs [3]						
- outstanding	**9,686**	**$ 28.96**	17,154	$ 28.16	22,945	$ 27.14
- exercisable	**7,522**	**$ 29.73**	10,805	$ 27.88	9,972	$ 25.29
Encana Replacement TSARs [4]						
- outstanding	**10,411**	**$ 31.97**	13,527	$ 31.17	16,357	$ 30.46
- exercisable	**8,461**	**$ 32.64**	8,066	$ 30.85	6,076	$ 28.43

[1] Thousands of units.
[2] Weighted average exercise price.
[3] Held by Encana Employees.
[4] Held by Cenovus Employees.

The closing share price at December 31, 2011 for Cenovus was $33.83 and for Encana was $18.89.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

($ millions)	2012	2013	2014	2015	2016	2017+	Total
	Expected Payment Date						
Pipeline Transportation (1)	$ 143	$ 137	$ 187	$ 311	$ 347	$ 2,754	$ 3,879
Operating Leases (Building Leases)	71	93	85	80	80	1,491	1,900
Product Purchases	19	18	19	19	6	-	81
Capital Commitments (2)	366	98	40	23	22	20	569
Other long-term Commitments	5	4	1	1	-	1	12
Decommissioning liabilities	69	2	7	2	2	6,458	6,540
Long-term debt (3)	-	-	814	-	-	2,745	3,559
Partnership Contribution Payable (3)	372	395	419	445	472	122	2,225
Total Payments (4)	$ 1,045	$ 747	$ 1,572	$ 881	$ 929	$13,591	$ 18,765
Product Sales	$ 52	$ 54	$ 56	$ 57	$ 60	$ 3	$ 282
Partnership Contribution Receivable (3)	$ 372	$ 393	$ 414	$ 436	$ 460	$ 119	$ 2,194

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Includes commitments related to jointly controlled entities.
(3) Principal component only. See notes to the Consolidated Financial Statements.
(4) Contracts undertaken by the Company on behalf of the FCCL Partnership are reflected at our 50 percent interest.

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements (which include amounts for projects awaiting regulatory approval), future building leases, marketing agreements, capital commitments and debt. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information please see the notes to the Consolidated Financial Statements.

Our commitments for 2012 increased by $385 million and in total increased by $2,537 million from 2010 mainly due to increased pipeline transportation commitments. These increased commitments were primarily for increased tolls and new agreements entered into in 2011 for crude oil transportation as we implement our marketing strategy to access new markets for our increasing crude oil production.

As at December 31, 2011, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 61 Bcf of natural gas at a weighted average price of $4.62 per Mcf.

In the normal course of business, we also lease office space for personnel who support field operations and for corporate purposes.

LEGAL PROCEEDINGS

We are involved in a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

Our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, are impacted by risks that are categorized as follows:

- Financial risks including market risk (fluctuations in commodity prices, foreign exchange rates and interest rates), credit risk, liquidity risk and cost overruns;
- Operational risks including capital and operating risks, reserves replacement risks and safety and environmental risks; and
- Regulatory risks including regulatory process and approval risks and changes to environmental regulations.

We are committed to identifying and managing these risks in the near-term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Market Risk Mitigation Policy, Enterprise Risk Management Policy, Credit Policy and risk management programs. Management monitors our risk strategies to proactively respond to changing economic conditions and to eliminate or mitigate risk. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally unforeseen issues arise unexpectedly and must be managed on an urgent basis.

A description of the risks affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2011 (see Additional Information).

FINANCIAL RISKS

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on our business.

We continue to implement our business model which focuses on developing low-risk and low-cost long-life resource properties. Cost containment and reduction strategies are in place to help ensure our controllable costs are efficiently managed. Counterparty and credit risks are closely monitored as is our liquidity to ensure access to cost effective credit. Sufficient access to cash resources, including our committed credit facility, is maintained to fund capital expenditures.

We partially mitigate our exposure to financial risks through the use of various financial instruments and physical contracts governed by our Market Risk Mitigation Policy which contains prescribed hedging protocols and limits. We have entered into various financial instrument agreements to mitigate exposure to commodity price risk volatility. The details of these instruments, including any unrealized gains or losses, as of December 31, 2011, are disclosed in the notes to the Consolidated Financial Statements and discussed in this MD&A. The financial instruments used are primarily swaps which are entered into with major financial institutions, integrated energy companies or commodities trading institutions and exchanges.

Global Economic Environment

The global economic environment has been turbulent and there continues to be uncertainty surrounding the European sovereign debt crisis. The European financial conditions along with a potential U.S. recession are among our most significant economic concerns.

We believe our financial position is strong with debt metrics currently at or below the low end of our target ranges. In addition, we have a fully available committed credit facility of $3.0 billion and capacity under two shelf prospectuses available to assist in addressing continued economic uncertainty and deteriorating global conditions. We also have a risk mitigation strategy that helps protect a portion of our cash flow each year.

Our ability to react to global economic uncertainties is enhanced by our ability to scale our capital programs to accommodate reduced cash flows.

Commodity Price Risk

Commodity price risk is the exposure to fluctuations in future market prices that results from the sales of various commodities in our operations.

We seek to reduce our exposure to commodity price risk through an integrated business strategy whereby a portion of operating supplies and feedstock is provided from internal operations. To further mitigate commodity price risk, we use derivative instruments in various operational markets to optimize our supply or production chain. We have partially mitigated our exposure to the crude oil commodity price risk on our crude oil sales with fixed price WTI swaps. We have partially mitigated our exposure to the natural gas commodity price risk on our natural gas sales with fixed price NYMEX and AECO swaps. We have partially mitigated our exposure to widening location or quality differentials for crude oil and natural gas with fixed price differential and basis swaps. We have partially mitigated our exposure to electricity consumption costs with a derivative power contract.

Credit Risk

Credit risk is the potential for loss if a counterparty in a transaction fails to meet its obligations in accordance with agreed terms.

A substantial portion of our accounts receivable are with customers in the oil and gas industry. This credit exposure is mitigated through the use of our Board-approved credit policy governing our credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. All financial derivative agreements are with major financial institutions in North America and Europe or with counterparties having investment grade credit ratings.

Liquidity Risk

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2011, no amounts were drawn on our committed credit facility. In addition, we had $1.5 billion in unused capacity under our Canadian shelf prospectus and

US$1.5 billion in unused capacity under our U.S. shelf prospectus, the availability of which are dependent on market conditions. Both of these prospectuses expire in the third quarter of 2012 and it is our intention to renew them prior to their expiration.

Foreign Exchange Risk

Foreign exchange risk is the exposure to fluctuations in foreign currency exchange rates in our operations. As our commodity sales are generally priced in U.S. dollars and our capital expenditures and expenses are paid in both U.S. and Canadian dollars, fluctuations in the exchange rate between the U.S. and Canadian dollar can have a significant effect on our financial results which are reported in Canadian dollars.

We reduce our exposure to foreign exchange risk through an integrated business strategy with a mix of U.S. and Canadian operations that creates a partial hedge to foreign exchange exposure. To further mitigate foreign exchange risk, we may enter into foreign exchange contracts or hedge our commodity exposures in Canadian dollars.

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

Interest Rate Risk

Interest rate risk is the impact of changing interest rates on earnings, cash flows and valuations. Although all of our debt portfolio was fixed rate debt at December 31, 2011, we have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt through the use of our commercial paper program and credit facilities. We may also enter into interest rate swap transactions from time to time as an additional means of managing the fixed/floating rate debt portfolio mix.

OPERATIONAL RISKS

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on our ability to achieve our objectives.

Capital and Operating Risks

Our ability to operate, generate cash flows, complete projects and value reserves is subject to capital and operating risks, including continued market demand for our products and other risk factors outside of our control, which include: general business and market conditions; economic recessions and financial market turmoil; the ability to secure and maintain cost effective financing for our commitments; the ability to obtain necessary regulatory, stakeholder and partner approvals; environmental and regulatory matters; unexpected cost increases; royalties; taxes; the availability of drilling and other equipment; the ability to access lands; weather; the availability of processing capacity; the availability and proximity of pipeline capacity; the availability of diluents to transport crude oil; technology failures; accidents; the availability of skilled labour and reservoir quality.

In the context of continued market volatility and in the face of the European credit crisis, which could result in a significant global economic recession, we are mindful of the need to maintain financial resiliency. Our capital programs are scalable in most cases, and we identified areas where we could slow down our spending in response to lower cash flows due to lower market prices. We expect to maintain strong financial metrics and substantial liquidity to respond to periods of lower prices if recessionary pressures impact our business.

Reserves Replacement Risk

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels and, therefore, our cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

To mitigate these risks, as part of the capital approval process, we evaluate projects on a fully risked basis, including geological risk and engineering risk. In addition, our asset teams undertake a project look back process. In this process, each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include technical and operational issues that positively and negatively impacted the project's results. Mitigation plans are developed for the issues that had a negative impact on results. These mitigation plans are then incorporated into the current year plan for the project. On an annual basis, these look back results are analyzed in relation to our capital program with the results and identified learnings shared across our company.

We utilize a peer review process to ensure that capital projects are appropriately risked and that knowledge is shared across our company. Peer reviews are undertaken primarily for early stage properties, although they may occur for any type of project.

Safety and Environmental Risk

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury or unanticipated environmental disruption. We are committed to safety in our operations and with high regard for the environment and stakeholders. These risks are managed by executing policies and standards that are designed to comply with or exceed government regulations and industry standards. In addition, we maintain a system, in respect of our assets and operations that identifies, assesses and controls safety, security and environmental risk and requires regular reporting to both senior management and our Board. The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including safety and the environment, for approval by our Board and oversees compliance with government laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and 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 strategies are utilized to restore the environment. In addition, security risks are managed through a security program designed to protect our personnel and assets.

We have an Investigations Committee whose mandate is to address potential violations of policies and practices and an Integrity Helpline that can be used to raise any concerns regarding operations, accounting or internal control matters.

When making operating and investing decisions, our business model allows flexibility in capital allocation to optimize investments focused on strategic fit, project returns, long-term value creation, and risk mitigation. We also mitigate operational risks through a number of other policies, systems and processes as well as by maintaining a comprehensive insurance program in respect of our assets and operations.

REGULATORY RISKS

Our 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 our existing and planned projects as well as impose a cost of compliance.

Regulatory and legal risks are identified by our operating and corporate groups, and our compliance with the required laws and regulations is monitored by our legal group in respect of our assets and operations. Our legal and environmental policy groups stay abreast of new developments and changes in laws and regulations to ensure that we continue to comply with prescribed laws and regulations. Of note in this regard, our approach to changes in regulations relating to climate change, royalty and regulatory frameworks is discussed below. To partially mitigate resource access risks, keep abreast of regulatory developments and be a responsible operator, we maintain relationships with key stakeholders and conduct other mitigation initiatives mentioned herein.

Environmental Regulation Risk

Environmental regulation impacts many aspects of our business. Regulatory regimes apply to all companies active in the energy industry. We are required to obtain regulatory approvals, licenses and permits in order to operate and we must comply with standards and requirements for the exploration, development and production of crude oil and natural gas and the refining, distribution and marketing of petroleum products. Regulatory assessment, review and approval are generally required before initiating, advancing or changing operations projects.

Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants and a number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in the U.S. and Canada. Adverse impacts to our business if comprehensive GHG regulation is enacted in any jurisdiction in which we operate may include, among other things, loss of markets, increased compliance costs, permitting delays, substantial costs to generate or purchase emission credits or allowances which may add costs to the products we produce and reduce demand for crude oil and certain refined products.

California has implemented climate change regulation in the form of a Low Carbon Fuel Standard that requires the reduction of life cycle carbon emissions from transportation fuels. This regulation currently differentiates oil sands crudes as high carbon intensity crude oils. As an oil sands producer, we are not directly regulated and will not have a compliance obligation; however, refiners in California will be required to meet the legislation. A number of studies produced on the subject, including one that was conducted by an organization that advised the legislation, suggest a wide range of carbon intensity values for oil sands crudes. We are well positioned within the sector given our typically low steam to oil ratio. This legislation has many complexities that are currently being addressed and in December 2011 the U.S. District Court for the Eastern District of California temporarily suspended the enforcement of the legislation due to several pending federal lawsuits challenging its implementation. We continue to monitor this development.

Beyond existing legal requirements, the extent and magnitude of any adverse impacts of any of these additional programs cannot be reliably or accurately estimated at this time because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance.

We intend to continue our activity to use scenario planning to anticipate future impacts, reduce our emissions intensity and improve our energy efficiency. We will also continue to work with governments to develop an approach to deal with climate change issues that protects the industry's competitiveness, limits the cost and administrative burden of compliance and supports continued investment in the sector.

The Government of Alberta has set targets for GHG emissions reductions. Regulations require facilities that emit more than 100,000 tonnes of GHG emissions per year to reduce their emissions intensity by 12 percent from a regulated baseline. To comply, companies can make operating improvements, purchase carbon offsets (or emission performance credits) or make a $15 per tonne contribution to an Alberta Climate Change and Emissions Management Fund. Cenovus currently has three facilities subject to this regulation. For the 2011 compliance year, we do not anticipate material costs in this regard.

Our efforts with respect to emissions management are founded in our industry leadership in:

- Oil sands technology development to reduce GHG emissions;
- Focus on energy efficiency; and
- Carbon dioxide sequestration.

In particular, our low steam to oil ratios at Foster Creek and Christina Lake translates directly into lower emissions intensity. Given the uncertainty in North American carbon legislation, our strategy for addressing the implications of emerging carbon regulations is proactive and is composed of three principal elements:

(1) Manage Existing Costs
When regulations are implemented, a cost is placed on our emissions (or a portion thereof) and while these are not material at this stage, they are being actively managed to ensure compliance. Factors such as effective emissions tracking, attention to fuel consumption and a focus on minimizing our steam to oil ratio help to support and drive our focus on cost reduction.

(2) Respond to Price Signals
As regulatory regimes for GHGs develop in the jurisdictions where we work, inevitably price signals begin to emerge. We have initiated an Energy Efficiency Initiative in an effort to improve the energy efficiency of our operations. The price of potential carbon reductions plays a role in the economics of the projects that are implemented. In response to the anticipated price of carbon reduction, we are also attempting, where appropriate, to realize associated value of our reduction projects.

(3) Anticipate Future Carbon Constrained Scenarios
We continue to work with governments, academics and industry leaders to develop and respond to emerging GHG regulations. By continuing to stay engaged in the debate on the most appropriate means to regulate these emissions, we gain useful knowledge that allows us to explore different strategies for managing our emissions and costs. These scenarios assist with our long range planning and our analyses on the implications of regulatory trends.

We incorporate the potential costs of carbon into future planning. Management and the Board review the impact of a variety of carbon constrained scenarios on our strategy, with a current price range from $15 to $65 per tonne of emissions applied to a range of emissions coverage levels. A major benefit of applying a range of carbon prices at the strategic level is that it can provide direct guidance to the capital allocation process. We also examine the impact of carbon regulation on our major projects. Although uncertainty remains regarding potential future emissions regulation, our plan is to continue to assess and evaluate the cost of carbon relative to our investments across a range of scenarios.

We recognize that there is a cost associated with carbon emissions. We believe that GHG regulations and the cost of carbon at various price levels have been adequately taken into consideration as part of our business planning and scenarios analysis. We believe that our development strategy, use of technology and focus on continuous improvement is an effective way to develop the resource, generate shareholder returns and coordinate overall environmental objectives with respect to carbon, air emissions, water and land. We are committed to transparency with our stakeholders and will keep them apprised of how these issues affect our operations.

Further information regarding Climate Change can be found in the Risk Factors section of our AIF for the year ended December 31, 2011 (see Additional Information).

ALBERTA'S REGULATORY FRAMEWORK

On April 5, 2011, the Government of Alberta released their draft of the Lower Athabasca Regional Plan ("LARP"), which was issued under the Alberta Land Stewardship Act. An updated draft of the LARP was released on August 29, 2011 after public consultation and stakeholder feedback was obtained. No substantial changes were made to the LARP from these consultations. The LARP is now awaiting provincial cabinet approval prior to being implemented.

The LARP identifies management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. If the land use designations for conservation, tourism and recreation areas are approved in their current form, some of our oil sands tenures may be cancelled, subject to compensation negotiations with the Government of Alberta. Access to some parts of our current resource properties may be restricted limiting the pace of development due to environmental limits and thresholds that may adversely affect the market price of our securities and the payment of dividends to our shareholders. The areas identified have no direct impact on our strategic plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications.

As part of the Government of Alberta's competitiveness review, a comprehensive review of Alberta's regulatory system called the Regulatory Enhancement Project (the "Project") was initiated in March 2010. The Project's goal is to create an effective regulatory system that will contribute to Alberta's overall competitiveness while protecting the environment, ensuring public safety and conservation of resources. The Project involved engagement with a broad range of stakeholders, including industry and led to a recommendation to the Minister of Energy, in the fourth quarter of 2010, for adoption of a coordinated policy framework and an integrated regulatory system for the upstream oil and gas sector. The Government of Alberta accepted the Project team's recommendations and decided to proceed in implementing those recommendations. There were no new developments in 2011.

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Water. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us or at all, or that such additional water will in fact be available to divert under such licenses. While we currently re-use a percentage of the water which we withdraw under license, there are no guarantees that our operations will continue to efficiently use water.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. This policy is available on our website at www.cenovus.com.

Our CR policy focuses on six commitment areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement; and (vi) Community Involvement and Investment. We will continue to externally report on our performance in these areas through our annual CR report.

The CR policy emphasizes our commitment to protect the health and safety of all individuals affected by our activities, including our workforce and the communities where we operate. We will not compromise the health and safety of any individual in the conduct of our activities. We will strive to provide a safe and healthy work environment and we expect our workers to comply with the health and safety practices established for their protection. Additionally, the policy includes reference to emergency response management, investment in efficiency projects, new technologies and research, and support of the principles of the Universal Declaration of Human Rights.

As our CR reporting process matures, indicators will be developed and integrated in our CR reporting that better reflect Cenovus's operations and challenges. Our online presence will be expanded through the corporate responsibility section of our website. In July 2011 we released our first comprehensive corporate responsibility report which can be found on our website at www.cenovus.com. This report was aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

ACCOUNTING POLICIES AND ESTIMATES

We are required to make judgments, assumptions and estimates in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates, and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further information on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The following discussion outlines the accounting policies and practices involving the use of estimates that are critical to understanding our financial results.

Basis of Presentation

Our results for the years ended December 31, 2011 and 2010 and the one month period from December 1, 2009 to December 31, 2009 represent our operations, cash flows and financial position as a stand-alone entity.

Our results for the period prior to the Arrangement, being January 1, 2009 to November 30, 2009, have been derived from the accounting records of Encana using the historical results of operations and historical basis of assets and liabilities of the businesses transferred to Cenovus. The historical consolidated financial statements include allocations of certain Encana expenses, assets and liabilities. In the opinion of management, the consolidated and historical carve-out consolidated financial statements reflect all adjustments necessary for a fair statement of the financial position and the results of operations and cash flows in accordance with previous GAAP.

Management believes that the assumptions underlying the historical consolidated financial statements are reasonable. However, as we operated as part of Encana and were not a stand-alone company prior to November 30, 2009, the historical consolidated financial statements included herein may not necessarily reflect our results of operations, financial position and cash flows had we been a stand-alone company during the period presented.

Oil and Gas Reserves

All of our oil and gas reserves were evaluated and reported to Cenovus by the IQREs as at December 31, 2011 in accordance with NI 51-101. The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to numerous uncertainties and various interpretations. Reserves estimates can be revised upward or downward based on the results of future drilling, testing, production levels, and economics of recovery based on cash flow forecasts. These revisions can have a significant impact on our future earnings because they will directly impact our DD&A rates, asset impairment calculations, accounting for business combinations and decommissioning costs.

Property, Plant and Equipment – DD&A

Development and production assets within property, plant and equipment are depreciated, depleted and amortized using the unit of production method based on estimated proved reserves determined using estimated future prices and costs. As a key component in the calculation of DD&A, the estimates of reserves can have a significant impact on net earnings, as a downward revision in our estimate of reserve quantities could result in a higher DD&A charge to net earnings.

Refining, marketing, corporate and other upstream assets, including pipelines and information technology assets, are depreciated on straight-line basis and are subject to our estimate of useful life and salvage value. These estimates can have a significant impact to net earnings as a decrease in the useful life or a lower salvage value could result in a higher DD&A charge to net earnings.

E&E Assets

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as E&E assets. The decision regarding technical feasibility and commercial viability of our E&E assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material change in the future.

Impairment of Assets

Property, plant and equipment and E&E assets are assessed for impairment at least annually or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. The impairment test is performed at the cash generating unit ("CGU") for development and production assets and other upstream assets. E&E assets are allocated to a related CGU containing development and production assets. Corporate assets are allocated on a reasonable and consistent manner to the CGUs to which they contribute to the future cash flows for the purposes of testing for impairment. For refining assets the impairment test is performed at each refinery independently.

The assessment of facts and circumstances that are used for impairment testing to suggest that the carrying amount of the assets may exceed its recoverable amount is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or CGUs for impairment, as well as the assessment of potential impairment reversals, requires that we estimate an asset's or CGU's recoverable amount. The recoverable amount calculation requires the use of estimates and assumptions which are subject to changes as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves and discount rates as well as future development and operating costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs. Details on the assumptions used in determining the recoverable amount can be found in the notes to the Consolidated Financial Statements.

Exchanges of Assets

Fair value estimates, which are used to determine the carrying value of a PP&E or E&E asset and recognize gains or losses on asset exchanges, requires a number of assumptions and estimates, including quantities of reserves, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and any non-controlling interest are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Goodwill is assessed for impairment at least annually. To assess impairment, the recoverable amount of the CGU to which the goodwill relates is compared to the carrying amount. If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

Decommissioning Liabilities

Provisions are recognized for the future decommissioning and restoration of our upstream oil and gas assets and refining assets at the end of their economic lives. Assumptions, based on current economic factors and experience to date which we believe are reasonable, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. The impact to net earnings over the remaining economic life of the assets could be significant due to the changes in cost estimates as new information becomes available. In addition, we determine the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. Details on the assumptions used in determining decommissioning liabilities can be found in the notes to the Consolidated Financial Statements.

Compensation Plans

The amount of compensation expense accrued for long-term performance-based compensation arrangements is subject to our best estimate of whether or not the performance criteria will be met and what the ultimate payout will be. Certain obligations for payments under our compensation plans are measured at fair value and therefore fluctuations in the fair value will affect the accrued compensation expense that is recognized. The fair value of the obligation is based on several assumptions including the risk-free interest rate, dividend yield, and the expected volatility of the share price and therefore is subject to measurement uncertainty.

Income Tax Provisions

Tax regulations and legislations and their interpretations in the various jurisdictions that we operate are subject to change. As a result, there are usually a number of tax matters under review. As such, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

Financial Instruments

The fair value of derivatives, which may be used to manage commodity price, foreign currency and interest rate exposures, are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Our assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and are therefore subject to measurement uncertainty.

IFRS Transition

OPENING BALANCE SHEET – CARRYING VALUE OF REFINERIES

On transition to IFRS, we elected to measure the carrying value of our refineries at their then estimated fair value, which permanently reduced their carrying value by approximately $2.6 billion. The fair value estimate is deemed to be the carrying value of the refineries at January 1, 2010. The reduced carrying value impacts DD&A expense recorded in future periods. DD&A expense for the year ended December 31, 2010 was reduced by $103 million as a result of the reduced carrying value.

OPENING BALANCE SHEET – FULL COST POOL

Under previous GAAP, we accounted for our oil and gas properties in one cost centre using full cost accounting. IFRS has no equivalent treatment. IFRS 1 - First-time Adoption of IFRS, permits full cost accounting companies to allocate their existing upstream PP&E net book value (full cost pool) to the unit of account level upon transition to IFRS using reserve information. Applying this exemption, the cost of our E&E assets were reclassified from PP&E to the new E&E asset category, and the remainder of our full cost pool was allocated using the estimated proved reserve values discounted at 10 percent at the transition date. This approach was consistent with the allocation method which was required to be used in our formation as part of the Arrangement. The IFRS allocation process did not affect the net book value of our PP&E at the date of transition as no IFRS impairments were recognized.

Under both IFRS and previous GAAP, the DD&A on our development and production PP&E is calculated using the unit-of-production method based on estimated proved reserves. However, under previous GAAP, we calculated our DD&A rate at the country cost centre level whereas under IFRS, our DD&A rates are calculated at the area level. The adoption of this policy resulted in a $135 million increase in our DD&A for the year ended December 31, 2010.

FUTURE CHANGES IN ACCOUNTING POLICIES

Joint Arrangements and Off Balance Sheet Activities

In May 2011, the IASB issued the following new and amended standards:

- *IFRS 10, "Consolidated Financial Statements"* ("IFRS 10") replaces *IAS 27, "Consolidated and Separate Financial Statements"* ("IAS 27") and Standing Interpretations Committee ("SIC") 12*, "Consolidation – Special Purpose Entities"*. IFRS 10 revises the definition of control and focuses on the need to have power and variable returns for control to be present. IFRS 10 provides guidance on participating and protective rights and also addresses the notion of "de facto" control. It also includes guidance related to an investor with decision making rights to determine if it is acting as a principal or agent.

- *IFRS 11, "Joint Arrangements"* ("IFRS 11") replaces *IAS 31, "Interest in Joint Ventures"* ("IAS 31") and *SIC 13, "Jointly Controlled Entities – Non-Monetary Contributions by Venturers"*. IFRS 11 defines a joint arrangement as an arrangement where two or more parties have joint control. A joint arrangement is classified as either a "joint operation" or a "joint venture" depending on the facts and circumstances. A joint operation is a joint arrangement where the parties that have joint control have rights to the assets and obligations for the liabilities, related to the arrangement. A joint operator accounts for its share of the assets, liabilities, revenues and expenses of the joint arrangement. A joint venturer has the rights to the net assets of the arrangement and accounts for the arrangement as an investment using the equity method.

- *IFRS 12, "Disclosure of Interest in Other Entities"* ("IFRS 12") replaces the disclosure requirements previously included in IAS 27, IAS 31, and *IAS 28, "Investments in Associates"*. It sets out the extensive disclosure requirements relating to an entity's interests in subsidiaries, joint arrangements, associates and unconsolidated structured entities. An entity is required to disclose information that helps users of its financial statements evaluate the nature of and risks associated with its interests in other entities and the effects of those interests on its financial statements.

- *IAS 27, "Separate Financial Statements"* has been amended to conform to the changes made in IFRS 10 but retains the current guidance for separate financial statements.

- *IAS 28, "Investments in Associates and Joint Ventures"* has been amended to conform to the changes made in IFRS 10 and IFRS 11.

The above standards are effective for annual periods beginning on or after January 1, 2013. Early adoption is permitted, providing the five standards are adopted concurrently. We are currently evaluating the impact of adopting these standards on our Consolidated Financial Statements.

Employee Benefits

In June 2011, the IASB amended *IAS 19, "Employee Benefits"* ("IAS 19"). The amendment eliminates the option to defer the recognition of actuarial gains and losses, commonly known as the corridor approach, rather it requires an entity to recognize actuarial gains and losses in Other Comprehensive Income ("OCI") immediately. In addition, the net change in the defined benefit liability or asset must be disaggregated into three components: service cost, net interest and remeasurements. Service cost and net interest will continue to be recognized in net earnings while remeasurements, which include changes in estimates and the valuation of plan assets, will be recognized in OCI. Furthermore, entities will be required to calculate net interest on the net defined benefit liability or asset using the same discount rate used to measure the defined benefit obligation. The amendment also enhances financial statement disclosures. This amended standard is effective for annual periods beginning on or after January 1, 2013, with modified retrospective application. Early adoption is permitted. We are currently evaluating the impact of adopting these amendments on our Consolidated Financial Statements.

Fair Value Measurement

In May 2011, the IASB issued *IFRS 13, "Fair Value Measurement"* ("IFRS 13") which provides a consistent and less complex definition of fair value, establishes a single source for determining fair value and introduces consistent requirements for disclosures related to fair value measurement. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 and applies prospectively from the beginning of the annual period in which the standard is adopted. Early adoption is permitted. We are currently evaluating the impact of adopting IFRS 13 on our Consolidated Financial Statements.

Financial Instruments

The IASB intends to replace *IAS 39, "Financial Instruments: Recognition and Measurement"* ("IAS 39") with *IFRS 9, "Financial Instruments"* ("IFRS 9"). IFRS 9 will be published in three phases, of which the first phase has been published.

The first phase addresses the accounting for financial assets and financial liabilities. The second phase will address the impairment of financial instruments, and the third phase will address hedge accounting.

For financial assets, IFRS 9 uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, and replaces the multiple rules in IAS 39. The approach in IFRS 9 is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39. For financial liabilities, although the classification criteria for financial liabilities will not change under IFRS 9, the approach to the fair value option for financial liabilities may require different accounting for changes to the fair value of a financial liability as a result of changes to an entity's own credit risk.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015 with different transitional arrangements depending on the date of initial application. We are currently evaluating the impact of adopting IFRS 9 on our Consolidated Financial Statements.

Presentation of Items of Other Comprehensive Income

In June 2011, the IASB issued an amendment to *IAS 1, "Presentation of Financial Statements"* ("IAS 1") requiring companies to group items presented within Other Comprehensive Income based on whether they may be subsequently reclassified to profit or loss. This amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with full retrospective application. Early adoption is permitted. We are currently evaluating the impact of adopting this amendment on our Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued the following amended standards:
- *IFRS 7, "Financial Instruments: Disclosures"* ("IFRS 7"), has been amended to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar arrangements.
- *IAS 32, "Financial Instruments: Presentation"* ("IAS 32") has been amended to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event.

The amendments to IFRS 7 are effective for annual periods beginning on or after January 1, 2013 and the amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, both requiring retrospective application. We are currently evaluating the impact of adopting the amendments to IAS 7 and IFRS 32 on our Consolidated Financial Statements.

OUTLOOK

In early 2012, certain economic factors have created optimism that the U.S. economy will gradually improve throughout the year. However, the European sovereign debt situation is expected to continue and may inhibit the North American economic recovery. Our outlook for 2012 depends on commodity prices including the effect of new market access for North American crude oil. Crude oil prices are expected to remain volatile as they are sensitive to economic growth and supply interruption risks.

For 2012, the price of WTI is expected to remain close to the average in 2011 as increased demand driven by emerging markets is anticipated to be offset by the return of Libyan supply. The expected increase in demand however remains sensitive to events in Europe as its sovereign debt problems continues to unfold. Also, the potential of further political uncertainty in Middle Eastern and northern African countries could create a material risk of supply disruptions which would negate the effect of returning Libyan supply.

For 2012, the WTI-WCS differential is expected to face pressures to narrow compared to 2011 as new coking capacity at our Wood River Refinery will be in operation for the full year and other additional refining capacity is brought on in the latter part of the year. These pressures are expected to be offset by growing North American crude oil production which will lead to greater pipeline congestion. However, new rail capacity, especially out of North Dakota, will serve to reduce pipeline congestion.

The economics for U.S. Midwest refineries for 2012 are expected to be lower than 2011 as average crack spreads decrease. The expected decrease in crack spreads is mostly due to lower discounts on feedstock costs as inland crude oil finds an outlet to refineries on the Gulf of Mexico through the Seaway Pipeline reversal in the middle of 2012.

For 2012 our strategic initiatives and key priorities include:
- Growth of production at Christina Lake with ramp up of phase C production and expected first production at phase D in the fourth quarter of 2012;
- Conventional crude oil production increasing in 2012 primarily as a result of the development of our tight oil opportunities at Lower Shaunavon and Bakken while pursuing additional growth opportunities;
- Improved production at Pelican Lake with the expansion of the polymer enhanced oil recovery program;
- Investment in the dewatering pilot project at Telephone Lake and the drilling of a second well pair as part of the Grand Rapids pilot project;
- Progressing the Telephone Lake and area project;
- Anticipating regulatory and partner approval for Narrows Lake phases A, B and C, perform additional engineering and start construction;
- Committing to transportation initiatives and advance new and expanded market development initiatives for our crude oil in step with a marketing strategy to deliver on our production growth;
- Progressing environmental strategy by setting internal goals;
- Demonstrating stable and reliable CORE operations at the Wood River Refinery; and
- Growing our dividend, at the discretion of our Board, while continuing to invest in long-term projects.

While we do not anticipate a significant impact to our business, our partner ConocoPhillips, announced its intention to split its Refining and Marketing and its Exploration and Production businesses into two stand-alone companies. If the split is completed, we expect our partnership and related agreements with ConocoPhillips to be amended to accommodate the separation and holding of the upstream assets and refining assets in two separate companies.

Our long-term objective is to focus on building net asset value and generating an attractive total shareholder return through the following strategies:

- Material growth in oil sands production, primarily through expansions at our Foster Creek and Christina Lake properties, and heavy oil production at Pelican Lake. We also have an extensive inventory of emerging resource play assets such as Narrows Lake, Grand Rapids and Telephone Lake, and have a 100 percent working interest in many of these assets;
- Continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach enabled by technology, innovation and continued respect for the health and safety of our employees, emphasis on environmental performance and meaningful dialogue with our stakeholders;
- Assess the potential for new crude oil projects on our existing properties at Pelican Lake, Weyburn, southern Alberta, Bakken and Lower Shaunavon as well as new regions focusing on tight oil opportunities;
- Fund growth internally through free cash flow generation mainly from our established conventional natural gas assets as well as proceeds generated from our ongoing portfolio management strategy to divest of non-core assets with any incremental cash requirements covered by additional debt financing;
- Lowering our commodity price risk profile through natural gas and refining integration as well as a consistent risk management hedging strategy; and
- Maintain a sustainable dividend with a priority expected to be placed on growing the dividend as part of delivering a solid total shareholder return.

Our updated business plan outlines our targets of reaching net oil sands production of approximately 400,000 barrels per day and total net oil production of approximately 500,000 barrels per day by the end of 2021. Continued expansions are planned at Foster Creek and Christina Lake, as well as new projects at Narrows Lake, Grand Rapids and Telephone Lake in order to achieve our production targets.

The key challenges that need to be effectively managed to enable our growth are commodity price volatility, access to markets, timely regulatory and partner approvals, environmental regulations and competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A.

Our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third for growth capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics which allow us to be financially resilient in times of lower cash flow. We will continue to develop our strategy with respect to capital investment and returns to shareholders. Future dividends are at the sole discretion of the Board and considered quarterly.

ADVISORY

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "plan", "forecast", "target", "project", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook", "potential", "may" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related schedules, projected future value or net asset value, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, anticipated finding and development costs, expected reserves and contingent and prospective resources estimates, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology including technology and procedures to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions inherent in our current guidance, available at www.cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; the estimation of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; the ability of us and ConocoPhillips to maintain our relationship and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation; changes in Alberta's regulatory framework, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF/Form 40-F for the year ended December 31, 2011 (see Additional Information).

OIL AND GAS INFORMATION

The bitumen contingent and prospective resources estimates were prepared effective December 31, 2011 by McDaniel & Associates Consultants Ltd., an independent qualified reserves evaluator. The estimates were based on the Canadian Oil and Gas Evaluation Handbook and comply with the requirements of NI 51-101.

- Contingent Resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. The estimate of contingent resources has not been adjusted for risk based on the chance of development. A discussion of contingencies applicable to our contingent resources can be found in the Oil and Gas Reserves section.

- Economic Contingent Resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2011 reserves evaluation, which comply with NI 51-101 requirements.

- Prospective Resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity. The estimate of prospective resources has not been adjusted for risk based on the chance of discovery or the chance of development.

- Best Estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent confidence level that the actual quantities recovered will equal or exceed the estimate.

- Low Estimate is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty, a 90 percent confidence level, that the actual quantities recovered will equal or exceed the estimate.

- High Estimate is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty, a 10 percent confidence level, that the actual quantities recovered will equal or exceed the estimate.

The economic contingent resources were estimated on a project level. The high and low estimates are arithmetic sums of multiple estimates which statistical principles indicate may be misleading as to volumes that may actually be recovered. The aggregated low estimate results shown may have a higher level of confidence than the individual projects, and the aggregated high estimate results shown may have a lower level of confidence than the individual projects.

Additional information relating to our oil and gas reserves and resources is presented in our AIF for the year ended December 31, 2011 (see Additional Information).

ABBREVIATIONS

The following is a summary of the abbreviations that have been used in this document:

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
NGLs	Natural gas liquids	GJ	Gigajoule
WTI	West Texas Intermediate	CBM	Coal Bed Methane
WCS	Western Canadian Select		
TM	Trademark of Cenovus Energy Inc.		

NON-GAAP MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as cash flow, operating cash flow, free cash flow, operating earnings, adjusted EBITDA, debt and capitalization and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations. The additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in this MD&A.

ADDITIONAL INFORMATION

The Arrangement refers to the plan of arrangement with Encana Corporation, effective November 30, 2009, resulting in the split of Encana into Cenovus and Encana, whereby Encana shareholders received, for each Encana common share held, one common share of each of Cenovus and the new Encana. Pursuant to the Arrangement, Cenovus commenced independent operations on December 1, 2009.

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

Additional information relating to Cenovus, including our AIF/Form 40-F for the year ended December 31, 2011, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at www.cenovus.com.