MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED JUNE 30, 2013

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc., ("we", "our", "Cenovus", or the "Company") dated July 23, 2013, should be read in conjunction with our June 30, 2013 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2012 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2012 MD&A ("annual MD&A"). This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The interim MD&A is approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports and the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated and have been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA"), 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 order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. 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 the Operating Results, Financial Results or Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On June 30, 2013, we had a market capitalization of approximately $23 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our average crude oil and NGLs production (collectively, "crude oil") in the first six months of 2013 was in excess of 175,600 barrels per day, our average natural gas production was 540 MMcf per day and our refinery operations processed an average of 428,000 gross barrels per day of crude oil feedstock into an average of 448,000 gross barrels per day of refined product.

Our Strategy

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a strong and sustainable dividend.

Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

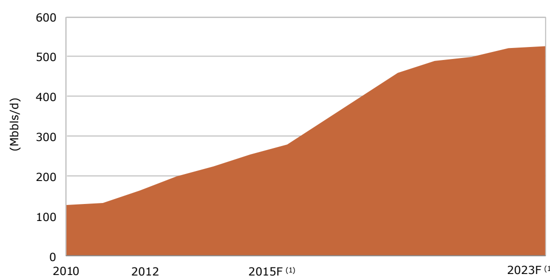
- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the impact of commodity price fluctuations.

To achieve our expected production targets, we anticipate our total annual capital investment to average between $3.3 and $3.7 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 our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Production

We plan to increase our net oil sands bitumen production to approximately 435,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 525,000 barrels per day by the end of 2023. We are focusing on the development of our substantial crude oil resources predominantly from Foster Creek, Christina Lake, Pelican Lake, Narrows Lake, Telephone Lake and our conventional tight oil opportunities. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 350-450 gross stratigraphic test wells each year for the next five years.

Total Crude Oil Production, net to Cenovus



(1) Expected net production capacity.

Oil Sands

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	Ownership Interest (percent)	Six Months Ended June 30, 2013 Net Production Volumes (bbls/d)	Six Months Ended June 30, 2013 Gross Production Volumes (bbls/d)	Current Expected Gross Production Capacity (bbls/d)
Existing Projects				
Foster Creek	50	55,665	111,330	310,000
Christina Lake	50	41,388	82,776	310,000
Narrows Lake	50	-	-	130,000
Emerging Projects				
Grand Rapids	100	-	-	180,000
Telephone Lake	100	-	-	300,000

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and located in the Athabasca region of northeastern Alberta.

Foster Creek is currently producing from phases A through E and has expansion work underway at phases F through H with added production capacity from phase F expected in the third quarter of 2014. In the first quarter of 2013, we submitted a joint application and environmental impact assessment ("EIA") for Foster Creek phase J. We anticipate receiving regulatory approval in the first quarter of 2015.

Christina Lake is producing from phases A through D. Our Phase E expansion commenced steam injection in June 2013 with first production achieved mid-July 2013. Expansion work is currently underway for phases F through G. We submitted an EIA for Christina Lake phase H in the first quarter of 2013 and anticipate receiving regulatory approval in the fourth quarter of 2014.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, and final partner approval in December 2012 for phase A. Site preparation and procurement is underway and we anticipate first production in 2017.

Two of our emerging projects are Grand Rapids and Telephone Lake. At our Grand Rapids project, 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. We anticipate receiving regulatory approval in the fourth quarter of 2013. At our Telephone Lake project, located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012. The pilot is expected to be completed by the end of 2013. In December 2011, we submitted a revised joint application and EIA due to an increase in the Telephone Lake project development area. We anticipate receiving regulatory approval in 2014.

Also located within the Athabasca region, is our wholly owned Pelican Lake property. Pelican Lake produces heavy oil using polymer flood technology and has an expected ultimate production capacity of 55,000 barrels per day. In the first six months of 2013 our production averaged 23,824 barrels per day.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flows, which provides diversification to our revenue stream and enables further development of our Oil Sands assets. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations and provides cash flows to help fund our growth opportunities.

($ millions)	Six Months Ended June 30, 2013 Crude Oil [1]	Natural Gas
Operating Cash Flow	486	223
Capital Investment	320	12
Operating Cash Flow net of Related Capital Investment	**166**	**211**

(1) Includes NGLs.

We have established conventional crude oil and natural gas producing assets and developing tight oil assets in Alberta. We also inject carbon dioxide to enhance oil recovery at our Weyburn operations in Saskatchewan.

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company.

	Ownership Interest (percent)	Current Nameplate Capacity (Mbbls/d)
Wood River	50	311
Borger	50	146

Our refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to mitigate volatility associated with North American commodity price movements. This segment also includes 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.

($ millions)	Six Months Ended June 30, 2013
Operating Cash Flow	848
Capital Investment	51
Operating Cash Flow net of Related Capital Investment	**797**

Technology and Environment

Technology development plays a key role in all aspects of our business. We advance technologies with the goal of improving the amount of crude oil we can access and extract from the ground while reducing the amount of water, natural gas and electricity consumed in our operations and minimizing environmental disturbance. The Cenovus culture fosters new ideas and new approaches and has a track record of developing innovative solutions that unlock previously inaccessible resources, potentially reducing costs, and building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return. The Board of Directors approved a dividend increase of 10 percent to $0.242 per share for each of the first and second quarters of 2013 compared to the same periods in 2012. The annualized dividend in 2012 was 10 percent higher than in 2011.

Net Asset Value

We measure our success in a number of ways with a key measure being growth in net asset value. We continue to be on track to reach our goal of doubling our December 2009 net asset value by the end of 2015.

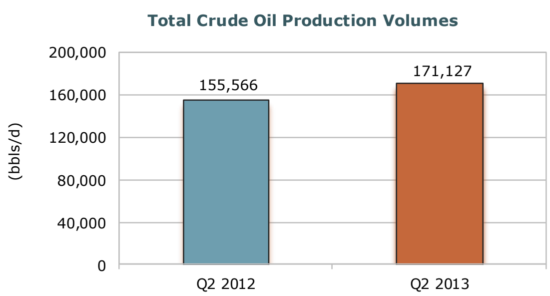
QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

The second quarter of 2013 continued to reflect the strength of our integrated approach. Upstream crude oil prices increased nine percent mainly due to the narrowing of the West Texas Intermediate ("WTI") to Western Canadian Select ("WCS") differential by 16 percent, averaging US$19.16 per barrel for the quarter (2012 - US$22.87 per barrel). Higher crude oil prices contributed to the 10 percent increase in upstream Operating Cash Flow. While increasing upstream Operating Cash Flow, the narrowing WTI-WCS differential increased the cost of refinery crude oil feedstock as both our refineries process discounted Canadian heavy crude oil which contributed to lower Operating Cash Flow from our refining operations. Refining Operating Cash Flow also decreased due to the processing of lower crude oil volumes as the result of an unplanned hydrocracker outage, partially offset by an improvement in market crack spreads. Overall, the integration of our businesses and growing crude oil production resulted in a four percent increase in total Operating Cash Flow.

Operational Results for the Second Quarter of 2013 as Compared to the Second Quarter of 2012

In the second quarter, crude oil production from our Oil Sands segment averaged 117,756 barrels per day, an increase of 15 percent, as production grew at all three of our producing properties. Average production at Christina Lake for the quarter was 38,459 barrels per day, a 35 percent increase, as phase D, our ninth SAGD expansion phase started to produce in the third quarter of 2012.

Within our Conventional segment, crude oil production averaged 53,371 barrels per day, a slight increase as a result of successful well performance in Alberta offsetting declines in our Saskatchewan production. Alberta crude oil production increased seven percent to an average of 32,151 barrels per day.



Our refining operations processed an average of 439,000 (Q2 2012 – 451,000) gross barrels per day of crude oil, of which 230,000 gross barrels per day was heavy crude oil (Q2 2012 – 229,000). We produced 457,000 gross barrels per day of refined products, a decrease of about 16,000 gross barrels per day, or three percent, due to an unplanned hydrocracker outage.

Other significant operational results in the second quarter compared to 2012 include:

- Completing our first planned turnaround at Christina Lake;
- Christina Lake phase E commencing steam injection in June 2013 with first production achieved mid-July 2013;
- Foster Creek production averaging 55,338 barrels per day, an increase of seven percent, partially due to reduced volumes in the second quarter of 2012 due to a full planned turnaround;
- Pelican Lake production averaging 23,959 barrels per day, an increase of seven percent as a result of improved performance with our infill drilling and polymer flood program;
- Natural gas production declining 10 percent to an average of 536 MMcf per day due to expected natural declines;
- Increasing our access to new sales markets with approximately 7,900 barrels per day transported by rail to the East Coast and the U.S.; and

- Exploration expense related to conventional assets increased from $68 million to $109 million in 2013. In addition, with the agreement to sell the Lower Shaunavon assets for $240 million, an impairment loss of $57 million was recorded to depletion, depreciation, and amortization ("DD&A").

Financial Results for the Second Quarter of 2013 as Compared to the Second Quarter of 2012

For an understanding of the trends and events that impacted our financial results, the following discussion should be read in conjunction with our 2012 annual MD&A.

Total Operating Cash Flow increased four percent to $1,119 million. Upstream Operating Cash Flow increased as a result of the narrowing of WTI-WCS price differentials, increased natural gas prices and growing crude oil production, partially offset by a rise in operating costs and lower realized risk management gains. Refining and Marketing Operating Cash Flow declined as a result of lower crude oil volumes processed and increased crude oil feedstock costs. Cash Flow declined by six percent to $871 million, as a result of a pre-exploration expense and higher cash tax. Operating Earnings were $255 million, a 10 percent decrease, due to higher DD&A primarily related to our Lower Shaunavon asset, partially offset by lower deferred income tax expense. Net earnings declined 55 percent to $179 million, primarily due to changes in unrealized risk management and unrealized foreign exchange gains and losses.

We paid a second quarter dividend of $0.242 per share (2012 – $0.22 per share), an increase of 10 percent over 2012, demonstrating our continuing commitment to pay a strong and sustainable dividend as part of delivering total shareholder return. Other financial highlights for the second quarter compared to 2012 include:

Revenues

Revenues of $4,516 million, increasing $302 million or seven percent as a result of:

- Our crude oil average sales price (excluding financial hedging) increasing nine percent to $69.61 per barrel;
- Crude oil sales volumes increasing eight percent;
- Our natural gas average sales price (excluding financial hedging) increasing 82 percent to $3.50 per Mcf;
- An increase in Refining and Marketing revenues as a result of higher refined product prices; and
- Higher condensate volumes used for blending, partially offset by decreased condensate prices.

Partially offsetting these increases in revenues were:

- Royalties increasing by 20 percent primarily due to higher crude oil sales volumes and crude oil prices; and
- Lower natural gas sales volumes of 10 percent, as a result of natural declines.

Operating Cash Flow

Operating Cash Flow of $1,119 million, increasing $41 million or four percent due to:

- An increase in upstream revenues as a result of higher average crude oil and natural gas sales prices and growing crude oil production volumes.

Partially offset by:

- An increase in upstream operating expenses of $78 million, partially from higher crude oil production; higher fuel costs, consistent with the increase in the benchmark AECO natural gas price; workover activities related to Foster Creek and Pelican Lake; and electricity, as a result of increases in market prices and consumption;
- Upstream realized risk management gains before tax of $24 million as compared to $96 million in 2012; and
- Operating Cash Flow from our Refining and Marketing segment decreasing $31 million due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads.

Capital Investment

Capital investment of $706 million, increasing from 2012 by seven percent, primarily due to phased expansions at our oil sands properties.

OPERATING RESULTS

Crude Oil Production Volumes

(barrels per day)	Three Months Ended June 30, 2013	Percent Change	2012	Six Months Ended June 30, 2013	Percent Change	2012
Oil Sands						
Foster Creek	**55,338**	**7%**	51,740	**55,665**	**2%**	54,477
Christina Lake	**38,459**	**35%**	28,577	**41,388**	**55%**	26,655
Pelican Lake	**23,959**	**7%**	22,410	**23,824**	**10%**	21,570
Conventional						
Heavy Oil	**16,284**	**4%**	15,703	**16,497**	**2%**	16,163
Light and Medium Oil	**36,137**	**-%**	36,149	**37,317**	**3%**	36,280
NGLs [1]	**950**	**(4)%**	987	**961**	**(9)%**	1,061
Total Crude Oil Production	**171,127**	**10%**	155,566	**175,652**	**12%**	156,206

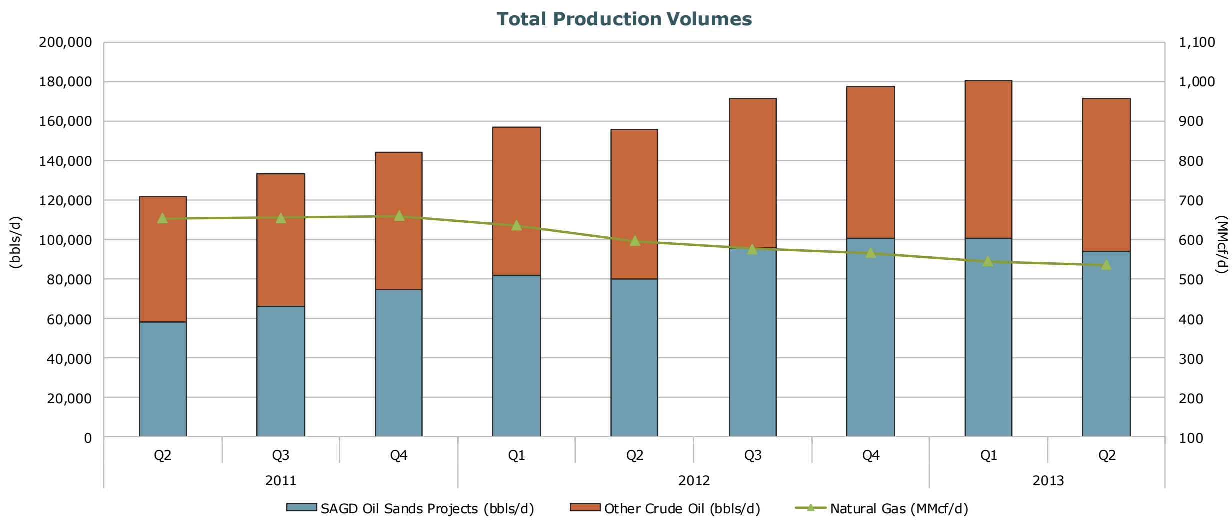
(1) *NGLs include condensate volumes.*

Our crude oil production rose for the three and six months ended June 30, 2013, primarily at Christina Lake as a result of the start-up of phase D in the third quarter of 2012. Production at Christina Lake was reduced by approximately 7,600 barrels per day for the quarter with the completion of our first major planned turnaround which resulted in 11 days of full production outage. Foster Creek production rose as 2012 production was reduced by approximately 7,400 barrels per day for the quarter given the completion of a 14 day planned turnaround. The Foster Creek planned turnaround for 2013 will be completed during the second half of the year. Pelican Lake production increased with improved performance from our infill drilling and polymer flood program. In Alberta, our heavy, light and medium crude oil production was higher as a result of better horizontal well performance from our current drilling program.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Conventional	**512**	563	**518**	579
Oil Sands	**24**	33	**22**	37
	536	596	**540**	616

In the three and six months ended June 30, 2013, our natural gas production declined as expected, in line with our decision to direct capital investment to our crude oil properties. In the low commodity price environment, we continue to manage natural gas capital spending by focusing on high rate of return projects.



Operating Netbacks

	Three Months Ended June 30, 2013		2012		Six Months Ended June 30, 2013		2012	
	Crude Oil [1] ($/bbl)	Natural Gas ($/Mcf)	Crude Oil [1] ($/bbl)	Natural Gas ($/Mcf)	Crude Oil [1] ($/bbl)	Natural Gas ($/Mcf)	Crude Oil [1] ($/bbl)	Natural Gas ($/Mcf)
Price [2]	**69.61**	**3.50**	63.92	1.92	**61.55**	**3.38**	69.26	2.22
Royalties	**5.03**	**0.04**	4.67	0.01	**4.19**	**0.05**	6.41	0.03
Transportation and Blending [2]	**2.55**	**0.08**	2.82	0.08	**2.69**	**0.12**	2.81	0.11
Operating Expenses	**17.24**	**1.16**	13.93	0.98	**16.18**	**1.15**	14.33	1.03
Production and Mineral Taxes	**0.61**	**(0.01)**	0.57	0.02	**0.58**	**0.01**	0.58	0.02
Netback Excluding Realized Risk Management	**44.18**	**2.23**	41.93	0.83	**37.91**	**2.05**	45.13	1.03
Realized Risk Management Gain (Loss)	**0.72**	**0.18**	1.64	1.39	**1.71**	**0.28**	(0.07)	1.20
Netback Including Realized Risk Management	**44.90**	**2.41**	43.57	2.22	**39.62**	**2.33**	45.06	2.23

(1) Includes NGLs.

(2) The heavy oil price and transportation and blending costs exclude the cost of purchase condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for the three months ended June 30 was $27.83 per barrel (2012 – $27.93 per barrel) and $29.52 per barrel (2012 – $29.07 per barrel) for the six months ended June 30.

In the three months ended June 30, 2013, our average crude oil netback, excluding realized risk management gains and losses, increased $2.25 per barrel from 2012 primarily due to higher sales prices, partially offset by increased operating costs and royalties. Higher sales prices were consistent with increased benchmark prices, with the average WTI-WCS differential narrowing in the second quarter to US$19.16 per barrel compared to US$22.87 per barrel in 2012.

For the six months ended June 30, 2013, our average crude oil netback, excluding realized risk management gains and losses, decreased $7.22 per barrel from 2012 primarily due to lower sales prices and higher operating costs, partially offset by a decrease in royalties at Foster Creek. Sales price decreases were consistent with lower benchmark prices, with the average WTI-WCS differential widening in the first six months of the year to US$25.56 per barrel compared to US$22.14 per barrel in 2012.

Our average natural gas netback, excluding realized risk management gains and losses, increased $1.40 and $1.02 per Mcf in the second quarter and year-to-date, respectively. This was predominantly due to higher sales prices, partially offset by higher per-unit operating costs as a result of the decline in production volumes.

Refining [1]

	Three Months Ended June 30, 2013	Percent Change	2012	Six Months Ended June 30, 2013	Percent Change	2012
Crude Oil Runs (Mbbls/d)	**439**	**(3)%**	451	**428**	**(4)%**	448
Heavy Oil	**230**	**-%**	229	**214**	**-%**	214
Crude Utilization (percent)	**96**	**(4)%**	100	**94**	**(5)%**	99
Refined Product (Mbbls/d)	**457**	**(3)%**	473	**448**	**(4)%**	469

(1) Represents 100 percent of the Wood River and Borger refinery operations.

Crude oil runs, crude utilization and refined product output declined for the three and six months ended June 30, as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in June.

Further information on the changes in our production volumes, items included in our operating netbacks and refining statistics can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management section of this MD&A and in the notes to the interim Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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 rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates (1)

	Six Months Ended June 30,				
	2013	2012	**Q2 2013**	Q1 2013	Q2 2012
Crude Oil Prices (US$/bbl)					
Brent Futures					
Average	**107.88**	113.61	**103.35**	112.64	108.76
End of Period	**102.16**	97.80	**102.16**	110.02	97.80
WTI					
Average	**94.26**	98.15	**94.17**	94.36	93.35
End of Period	**96.56**	84.96	**96.56**	97.23	84.96
Average Differential Brent-WTI	**13.62**	15.46	**9.18**	18.28	15.41
WCS					
Average	**68.70**	76.01	**75.01**	62.40	70.48
End of Period	**82.16**	58.34	**82.16**	82.71	58.34
Average Differential WTI-WCS	**25.56**	22.14	**19.16**	31.96	22.87
Condensate (C5 @ Edmonton) Average	**104.33**	104.70	**101.45**	107.23	99.32
Average Differential WTI-Condensate (Premium)	**(10.07)**	(6.55)	**(7.28)**	(12.87)	(5.97)
Refining Margin 3-2-1 Average Crack Spreads (2) (US$/bbl)					
Chicago	**29.30**	23.60	**31.06**	27.53	28.20
Midwest Combined ("Group 3")	**27.59**	24.89	**27.24**	27.93	28.28
Natural Gas Average Prices					
AECO ($/GJ)	**3.16**	2.06	**3.40**	2.92	1.74
NYMEX (US$/MMBtu)	**3.71**	2.48	**4.09**	3.34	2.22
Basis Differential NYMEX-AECO (US$/MMBtu)	**0.42**	0.30	**0.56**	0.27	0.39
Foreign Exchange Rate (US$ per C$1)					
Average	**0.984**	0.994	**0.977**	0.992	0.990

(1) *These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.*

(2) *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 using current month WTI based crude oil feedstock prices and a last in, first out accounting basis.*

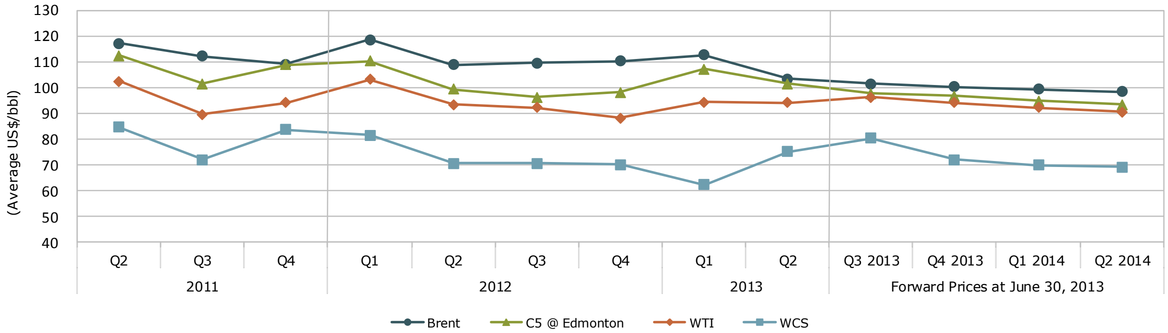
Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and is also a better indicator than WTI of changes in inland refined product prices. The average price of Brent crude oil decreased by US$5.41 per barrel and US$5.73 per barrel for the three and six months ended June 30, 2013, respectively compared to 2012, primarily caused by falling demand due to economic weakness in developed world economies, in addition to North American crude oil supply increases with U.S. and Canadian production rising significantly.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. Despite declines in the Brent benchmark, WTI increased slightly in the second quarter compared to 2012 as new pipeline capacity from the Cushing area to the U.S. Gulf Coast helped to relieve congestion that created sizable WTI price discounts to Brent. This narrowing of price differentials occurred despite above normal refinery outages in the Chicago and Group 3 markets. In the first six months of the year, WTI prices were roughly $4 per barrel lower than 2012 as a result of the weakening in the Brent crude oil price offset by reduced congestion in the Cushing area.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. This blended heavy oil is traded at a discount to the light oil benchmark WTI. The WTI-WCS average differential narrowed in the second quarter, compared to 2012, due to improved pipeline access from inland markets to the heavy crude oil refining complex in the U.S. Gulf Coast through a pipeline expansion and more effective use of existing pipeline infrastructure. Substantial increases in rail shipments also reduced pipeline congestion for all grades of crude. For the first six months of 2013, the WTI-WCS average differential widened due to severe levels of congestion early in the year prior to the increased pipeline capacity.

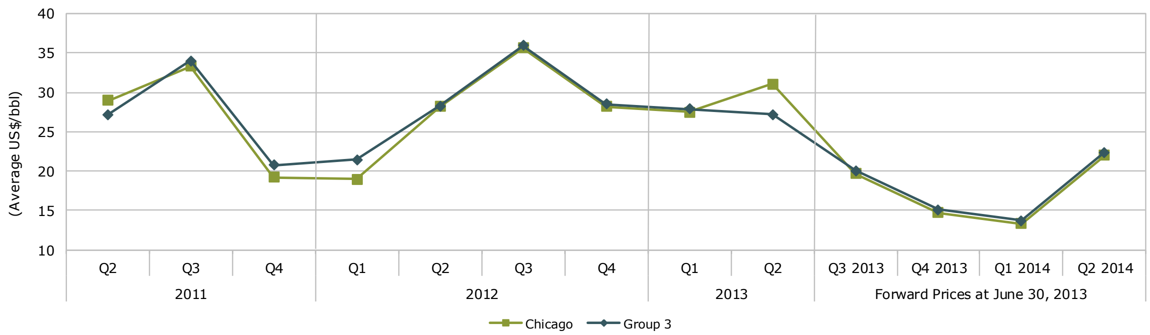
Crude Oil Benchmarks



Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from 10 percent to 33 percent. The WTI-Condensate differential is the Edmonton 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. Condensate differentials at Edmonton widened in both the three and six months ended June 30, 2013 due to strengthening U.S. condensate prices, as access to export markets improved and stronger premiums in the Edmonton market were needed to meet growing condensate requirements.

Refining 3-2-1 Crack Spread Benchmarks

Average crack spreads in the U.S. inland Chicago markets for the second quarter of 2013 rose while the Group 3 crack spread declined slightly. The strength in the Chicago market was due to an unusually large number of planned and unplanned refinery outages. For the first six months of 2013, the improvement in both Chicago and Group 3 crack spreads was due to the weak midcontinent product prices compared to the U.S. Gulf Coast light crude oil prices. This occurred primarily in the first quarter of 2012 as a result of high refinery runs and weak consumer demand.



Benchmark crack spreads are a simplified view of the market based on a last in, first out accounting basis 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 feedstock costs which are based on a first in, first out accounting basis.

Other Benchmarks

Average natural gas prices in the second quarter of 2013 increased significantly as the normal weather of the past winter helped absorb the significant storage surplus that had developed in the extremely warm winter of the previous year. Also helping with the price recovery has been a pattern of slowing supply growth coupled with strong industrial demand growth. For the first six months of 2013, the price increase over the previous year was less dramatic as the full effect of the differences in winter weather was not apparent in the market in the first quarter.

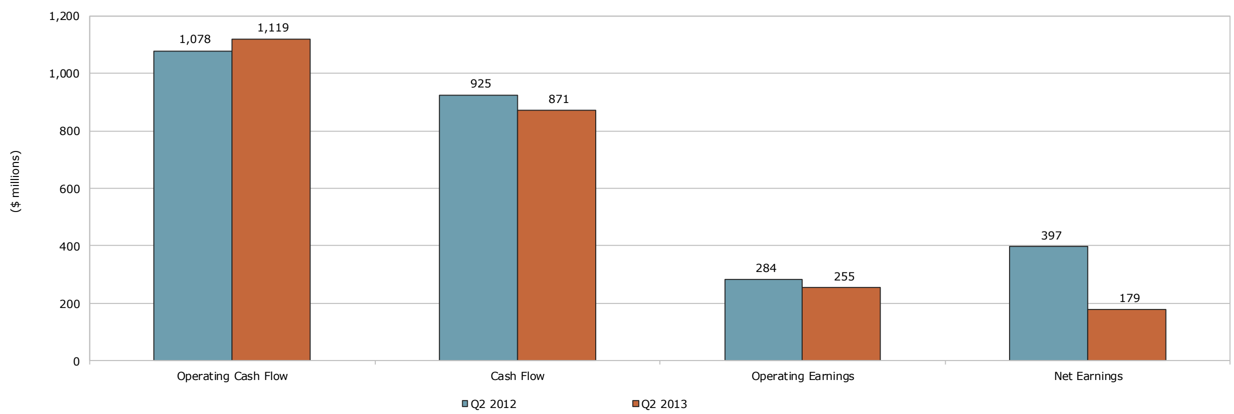
A decrease in the value of the Canadian dollar compared to the U.S. dollar has a positive impact on our revenues as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also inflates our current period's reported refining capital investment. For the three and six months ended June 30, 2013, the Canadian dollar weakened slightly relative to the U.S. dollar, compared to the same periods last year, but remained close to parity. The principal cause of exchange rate fluctuations has been changes in the U.S. dollar index (i.e. change in the value of the U.S. dollar rather than the Canadian dollar); although a general weakening of the global commodity prices has contributed to this pattern. The U.S. dollar tends to move in the opposite direction of commodity prices, while the Canadian dollar generally tends to move in the same direction as commodity prices.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The following key performance indicators are discussed in more detail within this section.

Operating Cash Flow, Cash Flow, Operating Earnings and Net Earnings



($ millions, except per share amounts)	Six Months Ended June 30, 2013	2012	2013 Q2	Q1	2012 Q4	Q3	Q2	Q1	2011 Q4	Q3	Q2
Revenues	**8,835**	8,778	**4,516**	4,319	3,724	4,340	4,214	4,564	4,329	3,858	4,009
Operating Cash Flow (1)	**2,330**	2,163	**1,119**	1,211	963	1,310	1,078	1,085	1,019	945	1,064
Cash Flow (1)	**1,842**	1,829	**871**	971	697	1,117	925	904	851	793	939
Per Share – Diluted	**2.43**	2.41	**1.15**	1.28	0.92	1.47	1.22	1.19	1.12	1.05	1.24
Operating Earnings (1) (2)	**646**	624	**255**	391	(188)	432	284	340	332	303	395
Per Share – Diluted (2)	**0.85**	0.82	**0.34**	0.52	(0.25)	0.57	0.37	0.45	0.44	0.40	0.52
Net Earnings (2)	**350**	823	**179**	171	(117)	289	397	426	266	510	655
Per Share – Basic (2)	**0.46**	1.09	**0.24**	0.23	(0.15)	0.38	0.53	0.56	0.35	0.68	0.87
Per Share – Diluted (2)	**0.46**	1.08	**0.24**	0.23	(0.15)	0.38	0.52	0.56	0.35	0.67	0.86
Capital Investment (3)	**1,621**	1,560	**706**	915	978	830	660	900	903	631	476
Cash Dividends	**367**	332	**183**	184	167	166	166	166	151	150	151
Per Share	**0.484**	0.44	**0.242**	0.242	0.22	0.22	0.22	0.22	0.20	0.20	0.20

(1) Non-GAAP measure and defined in this MD&A.
(2) We have restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more details.
(3) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.

Revenues Variance

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2012	**4,214**	**8,778**
Increase (Decrease) due to:		
Oil Sands	**139**	**89**
Conventional	**112**	**85**
Refining and Marketing	**116**	**70**
Corporate and Eliminations	**(65)**	**(187)**
Revenues for the Periods Ended June 30, 2013	**4,516**	**8,835**

Upstream revenues rose for the three months ended June 30, 2013 by 19 percent due to higher realized crude oil and natural gas prices, increased crude oil sales and condensate volumes, partially offset by increased royalties, lower natural gas production and reduced condensate prices.

Upstream revenues for the first six months of the year rose six percent due to increased crude oil sales and condensate volumes, higher realized natural gas prices, and reduced royalties, offset by lower realized crude oil prices, decreased condensate prices and a reduction in natural gas production.

Revenues for the three and six months ended June 30, 2013 generated by the Refining and Marketing segment increased four percent and one percent, respectively. Higher revenues from third party sales undertaken by the marketing group to provide operational flexibility offset declines in refining revenues as a result of lower refined product output due to planned maintenance in the first quarter and an unplanned hydrocracker outage in June, partially offset by refined product price increases.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices. Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Cash Flow

Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for 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 realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded in the calculation of Operating Cash Flow.

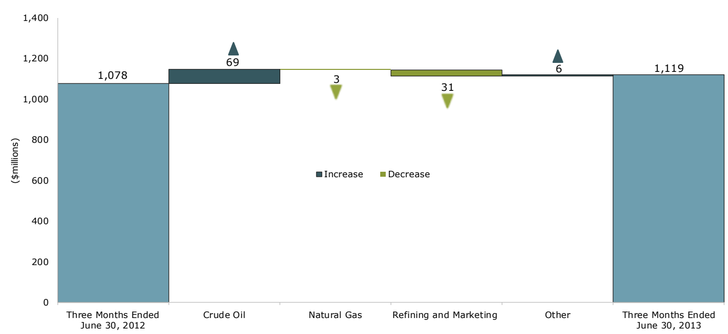
	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Revenues	**4,646**	4,279	**9,087**	8,843
(Add Back) Deduct:				
Purchased Product	**2,616**	2,508	**4,893**	5,097
Transportation and Blending	**460**	431	**1,018**	925
Operating Expenses	**462**	369	**905**	784
Production and Mineral Taxes	**9**	9	**19**	19
Realized (Gain) Loss on Risk Management Activities	**(20)**	(116)	**(78)**	(145)
Operating Cash Flow	**1,119**	1,078	**2,330**	2,163

Operating Cash Flow Variance for the Three Months Ended June 30, 2013 compared to June 30, 2012

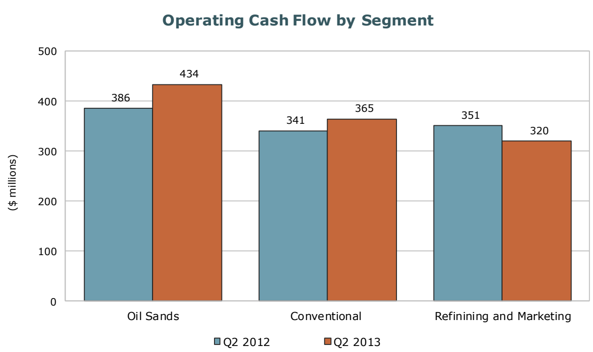
In the second quarter, Operating Cash Flow increased $41 million (four percent).

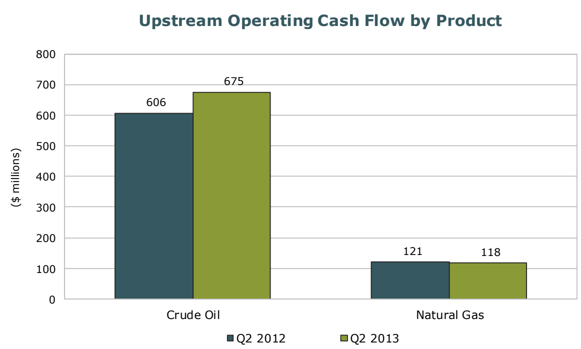
Operating Cash Flow from crude oil increased $69 million (11 percent) due to higher average sales prices and increased production volumes, partially offset by increased operating expenses and royalties.

Operating Cash Flow from natural gas decreased $3 million (two percent), due to lower realized risk management gains and reduced production volumes from expected natural declines, partially offset by increased sales prices.



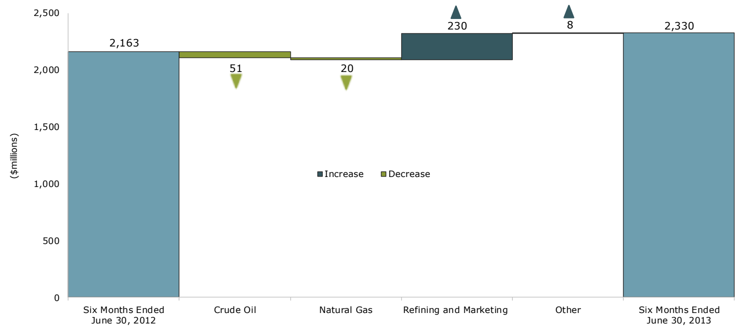
Refining and Marketing Operating Cash Flow declined $31 million (nine percent) due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads.





Operating Cash Flow Variance for the Six Months Ended June 30, 2013 compared to June 30, 2012

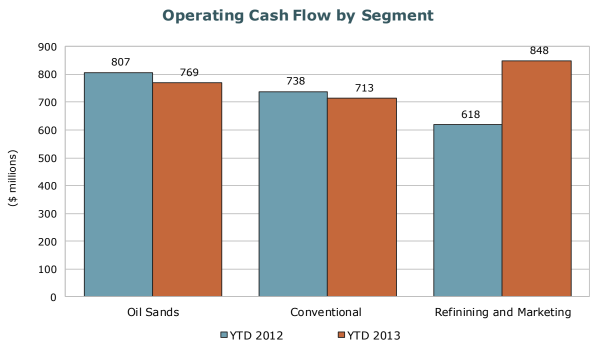
For the first six months of the year, Operating Cash Flow increased $167 million (eight percent).

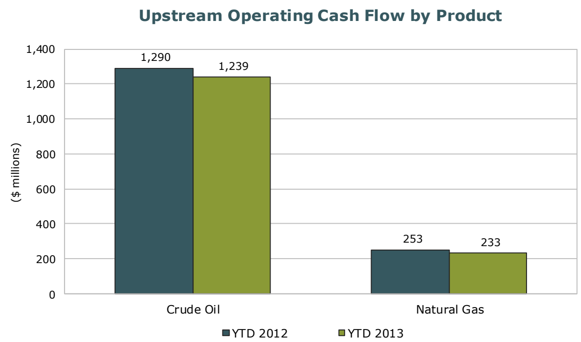


Operating Cash Flow from crude oil decreased $51 million (four percent) due to lower average sales prices and higher operating expenses partially offset by growing production volumes, lower realized risk management gains and a reduction in royalties.

Operating Cash Flow from natural gas declined $20 million (eight percent) due to lower realized risk management gains and reduced production volumes from expected natural declines, partially offset by increased sales prices.

Refining and Marketing Operating Cash Flow was higher by $230 million (37 percent) due to strong refining margins, resulting from discounted refinery crude oil feedstock costs and improved market crack spreads, primarily in the first quarter of 2013, partially offset by lower refined product output from planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter.





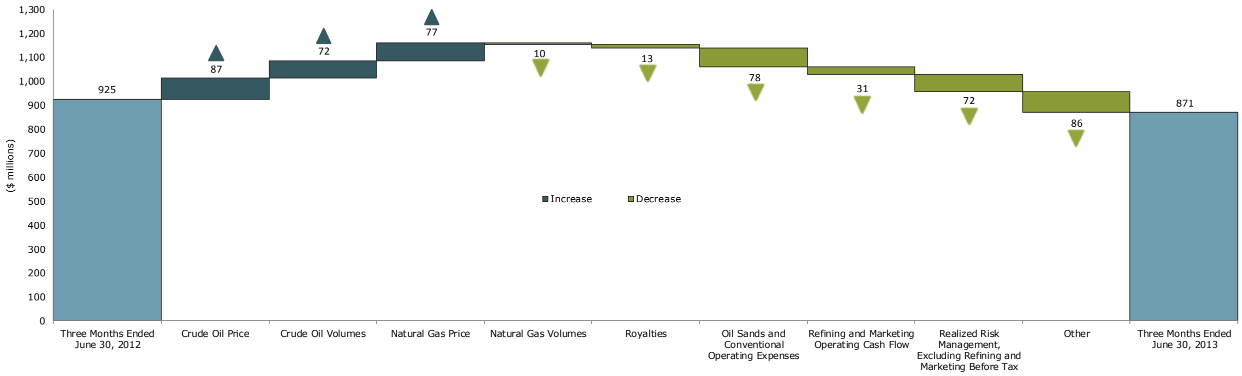
Additional details explaining the changes in Operating Cash Flow can be found in the Reportable Segments section of this MD&A.

Cash Flow

Cash Flow is a non-GAAP measure 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 is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Cash From Operating Activities	**828**	968	**1,723**	1,633
(Add Back) Deduct:				
Net Change in Other Assets and Liabilities	**(31)**	(20)	**(65)**	(52)
Net Change in Non-Cash Working Capital	**(12)**	63	**(54)**	(144)
Cash Flow	**871**	925	**1,842**	1,829

Cash Flow Variance for the Three Months Ended June 30, 2013 compared to June 30, 2012



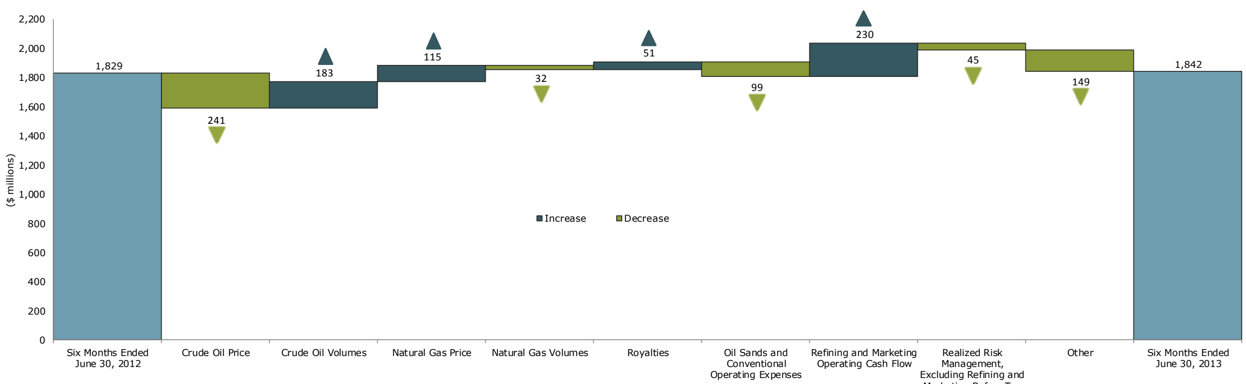
In the second quarter, our Cash Flow decreased $54 million or six percent due to:

- An increase in upstream operating expenses of $78 million, partially from higher crude oil production. On a per barrel basis, crude oil operating costs increased by $3.31 to $17.24 per barrel due to higher fuel costs, consistent with the increase in the benchmark AECO natural gas price; higher workover activities at Foster Creek and Pelican Lake; and rising electricity costs, as a result of increases in market prices and consumption;
- Realized risk management gains before tax, excluding Refining and Marketing, of $24 million compared to gains of $96 million in 2012;
- Pre-exploration expense of $63 million;
- A decline in Operating Cash Flow from Refining and Marketing of $31 million due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads;
- An increase in current income tax of $27 million as a result of higher Operating Cash Flow in Canada and the anticipated utilization in 2013 of all remaining U.S. federal net operating losses;
- An increase in royalties of $13 million primarily at our oil sands properties as a result of higher sales volumes and crude oil prices; and
- A 10 percent decline in natural gas production as a result of expected natural declines.

The decreases in our Cash Flow were partially offset by:

- A nine percent increase in our average sales price of crude oil to $69.61 per barrel;
- An 82 percent increase in our average sales price of natural gas to $3.50 per Mcf; and
- An increase in our crude oil sales volumes by eight percent.

Cash Flow Variance for the Six Months Ended June 30, 2013 compared to June 30, 2012



For the first six months of the year, our Cash Flow increased $13 million primarily due to:

- An increase in Operating Cash Flow from Refining and Marketing of $230 million due to strong refining margins, resulting from discounted refinery crude oil feedstock costs and improved market crack spreads, primarily in the first quarter of 2013 partially offset by lower refined product output from planned maintenance and an unplanned hydrocracker outage;
- A 10 percent increase in our crude oil sales volumes;
- A 52 percent increase in our average sales price of natural gas to $3.38 per Mcf; and
- A decrease in royalties of $51 million primarily at Foster Creek as a result of lower crude oil prices and increased capital, and in our Conventional segment, also as a result of declines in crude oil prices.

The increases in our Cash Flow were partially offset by:

- An 11 percent decrease in our average sales price of crude oil to $61.55 per barrel;
- An increase in upstream operating expenses of $99 million, mostly from higher crude oil production. On a per barrel basis, crude oil operating costs increased by $1.85 to $16.18 per barrel primarily due to higher fuel costs, consistent with the increase in the benchmark AECO natural gas price; rising electricity costs, as a result of higher market rates and consumption; rising waste fluid handling and trucking costs, and increased workover activities related to Foster Creek and Pelican Lake;
- Increased general and administrative expenses, excluding non-cash long-term incentive costs, due to higher rent and staffing costs;
- Pre-exploration expense of $63 million;
- Realized risk management gains before tax, excluding Refining and Marketing, of $86 million compared to gains of $131 million in 2012;
- Higher current income tax of $37 million as a result of higher Operating Cash Flow in Canada and the anticipated utilization in 2013 of all remaining U.S. federal net operating losses; and
- A 12 percent decline in natural gas production, primarily as a result of expected natural declines.

Operating Earnings

Operating Earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings is defined as net earnings excluding 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 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, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt and the effect of changes in statutory income tax rates.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Net Earnings	**179**	397	**350**	823
Add Back (Deduct):				
Unrealized Risk Management (Gain) Loss, after-tax (1)	**(21)**	(126)	**152**	(174)
Non-operating Unrealized Foreign Exchange (Gain) Loss, after-tax (2)	**97**	14	**144**	(24)
Gain (Loss) on Divestiture of Assets, after-tax	**-**	(1)	**-**	(1)
Operating Earnings	**255**	284	**646**	624

(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 decreased $29 million or 10 percent in the second quarter, primarily as a result of:

- Increased DD&A to reflect an impairment of $57 million on our Lower Shaunavon asset held for sale. In June 2013, we entered into an agreement to sell this asset and the sale was completed in early July 2013;
- Increase in DD&A of $44 million, excluding the Lower Shaunavon impairment, due to higher DD&A rates; and
- Lower Cash Flow as discussed above.

The decrease in Operating Earnings was partially offset by:

- A decline in deferred income tax expense of $126 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses, primarily as a result of decreased net income; and
- Exploration expense of $46 million (2012 – $68 million) related to previously capitalized E&E costs.

Year-to-date Operating Earnings increased $22 million or four percent, primarily as a result of:

- A decline in deferred income tax expense of $108 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses;
- A non-cash long-term incentive recovery in 2013 as compared to an expense in 2012; and
- Lower exploration expense related to previously capitalized E&E costs.

The increase in Operating Earnings was partially offset by:

- Increased DD&A of $156 million, including an impairment loss as discussed above; and
- Previously discussed decline in Cash Flow.

Net Earnings Variance

($ millions)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2012	**397**	**823**
Increase (Decrease) due to:		
Operating Cash Flow	**41**	**167**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss), after-tax	**(105)**	**(326)**
Unrealized Foreign Exchange Gain (Loss)	**(75)**	**(156)**
Expenses [(1)]	**(36)**	**(32)**
Depreciation, Depletion and Amortization	**(101)**	**(156)**
Exploration Expense	**(41)**	**(41)**
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gain (Loss)	**99**	**71**
Net Earnings for the Periods Ended June 30, 2013	**179**	**350**

(1) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, other (income) loss, net, (gain) loss on divestiture of assets, after-tax and Corporate and Eliminations operating expenses.

For the three and six months ended June 30, 2013, our net earnings decreased 55 percent and 57 percent, respectively, primarily due to:

- Items discussed within Operating Earnings and Cash Flow sections above;
- Unrealized risk management gains, after-tax, of $21 million in the quarter, compared to gains of $126 million in 2012 (year-to-date – unrealized risk management losses, after-tax, of $152 million, compared to gains of $174 million in 2012); and
- Unrealized foreign exchange losses of $84 million in the quarter, compared to losses of $9 million in 2012 (year-to-date – unrealized foreign exchange losses of $134 million, compared to gains of $22 million in 2012).

Net Capital Investment

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Oil Sands	**531**	454	**1,208**	1,090
Conventional	**134**	129	**332**	360
Refining and Marketing	**26**	24	**51**	22
Corporate	**15**	53	**30**	88
Capital Investment	**706**	660	**1,621**	1,560
Acquisitions	**1**	28	**4**	36
Divestitures	**-**	1	**(1)**	(65)
Net Capital Investment [(1)]	**707**	689	**1,624**	1,531

(1) Includes expenditures on PP&E and E&E.

Oil Sands capital investment in 2013 has been focused on the development of the expansion phases at Foster Creek and Christina Lake and facility expansion and infill drilling activities related to our Pelican Lake polymer flood. In addition, capital investment at Narrows Lake focused on site preparation, engineering and procurement for phase A subsequent to receipt of partner approval in December 2012. Construction of the phase A plant is scheduled to start in the third quarter of 2013. Capital investment includes the drilling of 321 gross stratigraphic test wells. The results of these stratigraphic test wells will be used primarily to support the expansion and development of our Oil Sands projects.

In 2013, Conventional capital investment has been centered on drilling, completion and recompletion programs as well as work on facilities in Saskatchewan and Alberta.

Our capital investment in the Refining and Marketing segment focused on capital maintenance and projects improving refinery reliability and safety in 2013.

Included in our capital investment is spending on technology development. Our teams look for ways to improve existing technology, evaluate new ideas and pursue new technology in an effort to enhance the recovery techniques we use to access crude oil and natural gas and improve our refining processes.

Capital investment in our Corporate and Eliminations segment decreased as costs related to tenant improvements and information technology were lower due to the move into our new office space in the first quarter of 2013.

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

Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our use 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 flows.

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Cash Flow	**843**	925	**1,814**	1,829
Capital Investment (Committed and Growth)	**706**	660	**1,621**	1,560
Free Cash Flow (1)	**137**	265	**193**	269
Dividends Paid	**183**	166	**367**	332
	(46)	99	**(174)**	(63)

(1) Free Cash Flow is a non-GAAP measure defined as Cash Flow less capital investment.

Over the next decade, we expect to increase our net crude oil production to approximately 525,000 barrels per day. In order to meet these project targets, we anticipate our total annual capital investment to average between $3.3 and $3.7 billion for the next decade. While internally generated cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. As at June 30, 2013, we had cash and cash equivalents of $825 million to fund future capital investment. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion of our financial metrics.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as heavy oil assets at Pelican Lake. This segment also includes the Athabasca natural gas assets and projects in the early stages of development such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

Conventional, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

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 Phillips 66. 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.

Revenue by Reportable Segment

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Oil Sands	**1,030**	891	**2,016**	1,927
Conventional	**538**	426	**1,047**	962
Refining and Marketing	**3,078**	2,962	**6,024**	5,954
Corporate and Eliminations	**(130)**	(65)	**(252)**	(65)
	4,516	4,214	**8,835**	8,778

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects and we also produce heavy oil from our wholly owned Pelican Lake operations. We have several emerging projects in the early stages of assessment, including Grand Rapids and Telephone Lake. The Oil Sands segment also includes 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 the second quarter compared to 2012 include:

- Christina Lake production increasing 35 percent, to an average of 38,459 barrels per day, with the start-up of phase D in the third quarter of 2012;
- During the quarter we successfully completed our first major planned turnaround at Christina Lake, an 11 day full outage, reducing production by approximately 7,600 barrels per day. Production ramped back up to expected levels by the end of the quarter;
- Christina Lake phase E, our tenth expansion phase, commencing steam injection in June 2013 with first production achieved mid-July 2013; and
- Foster Creek production averaging 55,338 barrels per day, an increase of seven percent, as 2012 production was reduced by approximately 7,400 barrels per day in the quarter given the 14 day planned turnaround.

Oil Sands – Crude Oil

Financial Results

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Gross Sales	**1,049**	909	**2,044**	1,996
Less: Royalties	**36**	26	**57**	91
Revenues	**1,013**	883	**1,987**	1,905
Expenses				
Transportation and Blending	**415**	395	**926**	844
Operating	**181**	125	**344**	263
(Gain) Loss on Risk Management	**(7)**	(15)	**(36)**	3
Operating Cash Flow	**424**	378	**753**	795
Capital Investment	**530**	454	**1,206**	1,085
Operating Cash Flow net of Related Capital Investment	**(106)**	(76)	**(453)**	(290)

Capital expenditures in excess of Operating Cash Flow for the Oil Sands segment are funded through Operating Cash Flow generated by our conventional and refining operations.

Production

(barrels per day)	Three Months Ended June 30, 2013	Percent Change	2012	Six Months Ended June 30, 2013	Percent Change	2012
Foster Creek	**55,338**	**7%**	51,740	**55,665**	**2%**	54,477
Christina Lake	**38,459**	**35%**	28,577	**41,388**	**55%**	26,655
	93,797	**17%**	80,317	**97,053**	**20%**	81,132
Pelican Lake	**23,959**	**7%**	22,410	**23,824**	**10%**	21,570
	117,756	**15%**	102,727	**120,877**	**18%**	102,702

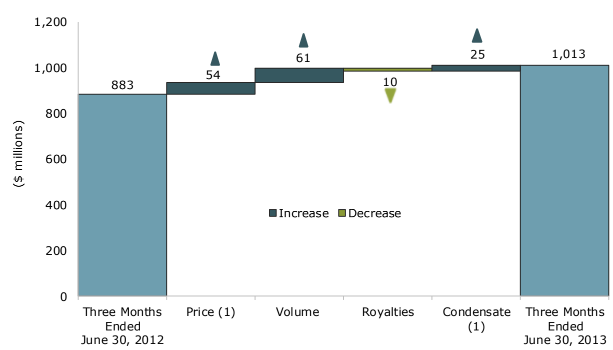
Three Months Ended June 30, 2013 Compared to June 30, 2012

Revenue Variance

Pricing

In the second quarter, our average crude oil sales price was $64.09 per barrel, nine percent higher than 2012, generally consistent with the increase in the WCS benchmark price and strengthening of the Christina Dilbit Blend ("CDB") price.

For the three months ended, approximately 92 percent of our Christina Lake production was sold as CDB (2012 – 70 percent), which sells at a discount to WCS. The CDB price differential to WCS improved approximately $0.50 per barrel compared to 2012, as CDB continues to gain wider market acceptance in 2013. The remaining Christina Lake production was sold as part of the WCS stream and is subject to a quality equalization charge.



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Production

In the second quarter, Foster Creek production increased, in comparison to 2012, as 2012 production volumes were reduced by approximately 7,400 barrels per day in the quarter given the completion of a 14 day planned turnaround. The 2013 turnaround is planned for the second half of the year and we expect to return to near full production capacity by the end of the year. We continue to experience a higher than usual number of wells off production as a result of downhole mechanical issues. Efforts are underway to resolve the downhole issues and we expect production to return to near full capacity of 120,000 gross barrels per day later in 2013. We continue to have three well pads in steam rampdown that are being converted to the blowdown phase (when steam injection is no longer occurring). At the later stage of production life, we start to reduce the steam injection and shift to co-injection of methane to optimize the use of steam and reduce energy output. When well pads convert to blowdown the impact is positive on the overall project as the steam gets redirected to newer wells. The first well pad started rampdown in the fourth quarter of 2011 and steam injection is no longer occurring.

Christina Lake production increased with the start-up of phase D in the third quarter of 2012. Production at Christina Lake was reduced by approximately 7,600 barrels per day with the completion of our first major planned turnaround which resulted in 11 days of full production outage. Production ramped back up to expected levels by the end of the quarter.

Pelican Lake production continues to increase due to infill wells being brought on-stream throughout 2012 and 2013.

Royalties

Royalty calculations for our Oil Sands projects differ between properties and are based on government prescribed pre and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price. Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent) to the gross revenues from the project. Gross revenues are a function of volumes and realized prices.

Royalties for Foster Creek and Pelican Lake, post-payout projects, use an annualized calculation which is based on the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of volumes, realized prices and allowed operating and capital costs.

Higher sales volumes and crude oil prices at all three of our producing properties contributed to a $10 million increase in royalties in the second quarter.

Effective Royalty Rates

(percent)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Foster Creek	**5.7**	4.6	**4.5**	9.7
Christina Lake	**5.6**	7.2	**5.6**	7.1
Pelican Lake	**5.8**	4.2	**6.0**	4.4

Expenses

Transportation and Blending

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce its viscosity in order to transport the product to market. Transportation and blending costs rose $20 million or five percent in the second quarter. The blending (condensate) portion of the cost increase was $25 million, mainly due to the higher condensate volumes required for the additional production at Christina Lake, partially offset by decreases in our average cost of condensate. Transportation charges were lower due to increased volumes shipped on the Trans Mountain pipeline system where we have a long-term commitment for firm service, resulting in lower transportation costs for our net share.

Operating

Our operating costs for the second quarter were primarily for workforce, workover activities, fuel and repairs and maintenance. In total, operating costs increased $56 million or $4.06 per barrel.

Per-unit Operating Costs

($/bbl)	Three Months Ended June 30, 2013	Percent Change	2012	Six Months Ended June 30, 2013	Percent Change	2012
Foster Creek	**16.19**	**30%**	12.49	**15.08**	**19%**	12.68
Christina Lake	**16.83**	**34%**	12.52	**14.66**	**6%**	13.84
Pelican Lake	**22.21**	**25%**	17.71	**20.75**	**23%**	16.81

At Foster Creek operating costs rose $20 million. The increase was associated with:

- Workover activities, as we experienced a higher number of wells off production due to downhole mechanical issues;
- Fuel prices consistent with the rising benchmark AECO natural gas price;
- Fuel volumes due to production growth; and
- Electricity as a result of increased market rates on purchased electricity while our cogeneration units were down for maintenance.

Increases were partially offset by lower repairs and maintenance with the completion of a full planned turnaround during the second quarter of 2012.

Christina Lake operating costs increased $21 million as a result of:

- Higher fuel prices consistent with the benchmark AECO natural gas price;
- Increasing fuel usage as a result of rising production;
- Additional repairs and maintenance costs mainly related to the planned turnaround;
- Higher workforce costs associated with increased production and the planned turnaround; and
- Higher waste fluid handling and trucking costs due to treating and emulsion hauling associated with production growth and the planned turnaround.

Operating costs at Pelican Lake increased $15 million due to higher workover activities, as a result of a higher frequency of downhole equipment failures on some of the injection wells during annual inspection, increased electricity cost (consistent with rising market prices and higher usage related to higher water and polymer injection to support expansion) and increased repairs and maintenance related to planned and unplanned maintenance on the battery and impacts of wet weather.

Risk Management

Risk management activities resulted in realized gains of $7 million (2012 – realized gains of $15 million) in the second quarter of 2013, consistent with our contract prices exceeding average benchmark prices.

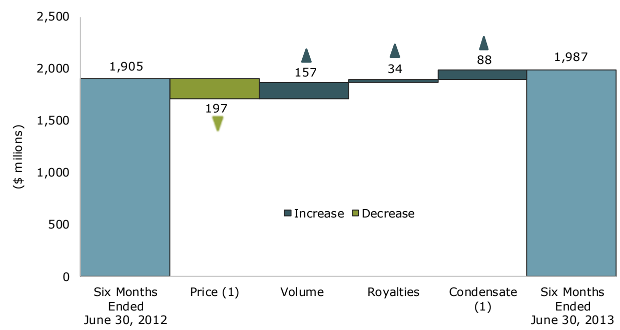
Six Months Ended June 30, 2013 Compared to June 30, 2012

Revenue Variance

Pricing

For the six months ended June 30, 2013, our average crude oil sales price was $54.60 per barrel, a 14 percent decrease from 2012, generally consistent with the decrease in the WCS benchmark price and strengthening of the CDB price.

For the six months ended, approximately 87 percent of our Christina Lake production was sold as CDB (2012 – 60 percent), which sells at a discount to WCS. The CDB price differential to WCS improved approximately $2.00 per barrel compared to 2012, as CDB continues to gain wider market acceptance in 2013. The remaining Christina Lake production was sold as part of the WCS stream and is subject to a quality equalization charge.



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Production

In the first six months of the year, production rose slightly at Foster Creek with the completion of the planned turnaround in 2012, partially offset by a higher than usual number of wells off production from downhole mechanical issues as discussed above in the second quarter results. The substantial increase in production at Christina Lake resulted from the start-up of phase D in the third quarter of 2012. Production at Christina Lake was reduced by approximately 3,800 barrels per day during the first six months of the year with the completion of our first major planned turnaround which resulted in 11 days of full production outage. Pelican Lake production rose as a result of infill wells being brought on-stream in 2012 and 2013.

Royalties

In the first six months of the year royalties decreased $34 million primarily related to lower realized prices and increased capital expenditures at Foster Creek resulting in a royalty calculation based on gross revenues.

Expenses

Transportation and Blending

Transportation and blending costs rose $82 million or 10 percent year-to-date. The blending (condensate) portion of the cost increase was $88 million, mainly due to the higher condensate volumes required for additional production from Christina Lake, partially offset by a decrease in our average cost of condensate. Transportation charges were lower due to increased volumes shipped on the Trans Mountain pipeline system where we have a long-term commitment for firm service since February 2012, resulting in lower transportation costs for our net share.

Operating

In the first six months of 2013, operating costs were primarily for workforce, workover activities, fuel and repairs and maintenance. In total, operating costs increased $81 million.

At Foster Creek operating costs rose $23 million related to higher fuel prices and volumes, workover activities, workforce and electricity, partially offset by lower repairs and maintenance.

Christina Lake operating costs increased $40 million mainly due to our production growth. Increases were also related to higher fuel prices and volumes, additional waste fluid handling and trucking costs, higher workforce costs and repairs and maintenance associated with the planned turnaround.

Higher operating costs at Pelican Lake were for increased workover activities due to equipment failure, increased chemical consumption related to expansion of the polymer flood, electricity (with increases in market rates and higher consumption) and repairs and maintenance related to planned and unplanned maintenance on the battery and impacts of wet weather.

Risk Management

Risk management activities resulted in realized gains of $36 million (2012 – realized losses of $3 million) in the first six months of 2013, consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands also includes our 100 percent owned natural gas operation in Athabasca and other minor natural gas properties. Our natural gas production for the three and six months ending June 30, 2013 was 24 MMcf per day and 22 MMcf per day, respectively, decreasing as the result of expected natural declines. In addition, the internal use of our natural gas production at Foster Creek increased in the six months ended June 30, 2013 due to the resolution of deliverability issues encountered in the first quarter of 2012.

Operating Cash Flow was $10 million in the first six months of 2013 (2012 – $13 million) due to higher sales prices offset by lower production volumes.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Foster Creek	**189**	169	**399**	328
Christina Lake	**162**	140	**337**	278
	351	309	**736**	606
Pelican Lake	**111**	104	**254**	243
Narrows Lake	**25**	9	**50**	18
Telephone Lake	**17**	13	**70**	104
Grand Rapids	**8**	5	**26**	39
Other [(1)]	**19**	14	**72**	80
Capital Investment [(2)]	**531**	454	**1,208**	1,090

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

Foster Creek

Capital investment for the three and six months ended June 30, 2013 was higher primarily as a result of increased phase G spending on module assembly, piling and procurement, and phase H site preparation, piling and procurement. Capital spending on phase F has been at consistent levels to 2012. Year-to-date spending includes the drilling of 111 gross stratigraphic test wells (2012 – 124 gross wells) and spending on maintenance capital and the construction of a new camp facility.

Christina Lake

Christina Lake capital investment increased for the three and six months ended June 30, 2013 primarily due to phase F procurement, plant construction and major equipment fabrication and phase E plant and well pad construction and drilling of well pairs, with steam injection commencing in June 2013 and first production achieved mid-July 2013. Capital investment also included the drilling of stratigraphic test wells (2013 – 69 gross wells;

2012 – 97 gross wells) in the first six months of the year and higher spending on maintenance and infrastructure capital. Year-to-date increases were partially offset by the completion of phase D construction in the second quarter of 2012.

Pelican Lake

Pelican Lake capital investment was higher in the three and six months ended June 30, 2013 due to detailed engineering and procurement of long lead equipment for a new battery currently planned to be constructed commencing in 2014, partially offset by lower infill drilling and maintenance capital. Facilities spending focused on upgrades to the emulsion pipelines, corrosion mitigation on pad piping and electrical transformer upgrades to increase capacity for future facilities and infill pad power requirements. Capital investment also included the drilling of six stratigraphic test wells (2012 – five wells).

Narrows Lake

Capital investment increased at Narrows Lake in the second quarter and in the first six months of the year, as site preparation, engineering and procurement for phase A progressed subsequent to final partner approval in December 2012. Capital investment also included the drilling of 26 gross stratigraphic test wells (2012 – 38 gross wells).

Telephone Lake

Capital investment rose slightly in the second quarter and decreased year-to-date, with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. The dewatering pilot, which commenced in the fourth quarter of 2012, continued in 2013 with the removal and reinjection of water and monitoring of results. Capital investment also included the drilling of 28 stratigraphic test wells (2012 – 29 wells).

Gross Production Wells Drilled (1)

	Six Months Ended June 30,	
	2013	2012
Foster Creek	**25**	11
Christina Lake	**11**	11
	36	22
Pelican Lake	**31**	29
Grand Rapids	**-**	1
Other	**-**	2
	67	54

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

Future Capital Investment

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. Additional production capacity of 45,000 gross barrels per day is expected from phase F in the third quarter of 2014, with production from phases G and H expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. Foster Creek capital investment for 2013 is forecasted to be between $790 million and $870 million.

First steam was achieved at Christina Lake phase E in the second quarter of 2013 and first production was achieved mid-July 2013. In the fourth quarter of 2012, we received regulatory approval to add cogeneration facilities at Christina Lake and to increase expected total gross production capacity by 10,000 barrels per day at each of phases F and G. Expansion work on these phases is continuing in 2013 as planned. We submitted a joint application and EIA to regulators in March 2013 for phase H expansion, for which we expect to receive regulatory approval in the fourth quarter of 2014. In 2013, Christina Lake capital investment is forecasted to be between $630 million and $670 million.

At Pelican Lake, we are continuing with the expansion of the infill drilling program in addition to piloting new techniques to optimize production. In 2013, the rate at which we are expanding the polymer flood has slowed to better match our production growth. In 2013, Pelican Lake capital investment is forecasted to be between $480 million and $520 million.

In 2012, we received regulatory approval for Narrows Lake phases A, B and C, and partner approval for phase A. Site preparation, engineering and procurement are underway, with construction of the phase A plant scheduled to start in the third quarter of 2013. The first phase of the project is anticipated to have a production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Capital investment in the project is forecasted to be between $140 million and $160 million in 2013.

Additional capital investment of approximately $270 million to $300 million in 2013 is expected for our emerging SAGD projects, including Grand Rapids and Telephone Lake. We anticipate regulatory approval for Grand Rapids by the end of 2013. Steam injection started on the second pilot well pair in the third quarter of 2012 and first production was achieved in February 2013. The Grand Rapids pilot is experiencing facility constraints that have impacted the production of both well pairs. A facility turnaround is expected to mitigate these constraints in the third quarter of 2013. At Telephone Lake, we are advancing the regulatory application for the project and anticipate receiving approval in 2014. In 2013, we are continuing with the operation of the dewatering pilot and plan to complete the pilot in the fourth quarter of 2013, as we have successfully replaced water and confined air, displacing approximately 50 percent of top water in the pilot area to date.

Stratigraphic Test Wells

Consistent with our strategy to unlock the value of our resource base, we completed another stratigraphic test well program over the winter drilling season. The stratigraphic test wells drilled at Foster Creek, Christina Lake and Narrows Lake are to support the expansion phases, 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.

To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed in the winter months, typically between the end of the fourth quarter and the end of the first quarter. In 2012, we developed the SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow stratigraphic well drilling to occur year-round in remote drilling locations. We have drilled 26 wells using the SkyStrat™ drilling rig in the last two years.

Gross Stratigraphic Test Wells Drilled

	Six Months Ended June 30,	
	2013	2012
Foster Creek	**111**	124
Christina Lake	**69**	97
	180	221
Pelican Lake	**6**	5
Narrows Lake	**26**	38
Telephone Lake	**28**	29
Grand Rapids	**1**	41
Other	**80**	85
	321	419

CONVENTIONAL

Our Conventional operations include the development and production of crude oil and natural gas in Alberta and Saskatchewan. The Conventional properties in Alberta comprise predictable cash flow producing crude oil and natural gas assets and developing tight oil assets. In Saskatchewan, our Conventional properties are predominantly crude oil producing properties, most notably the carbon dioxide enhanced oil recovery project in Weyburn. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced.

Significant factors that impacted our Conventional segment in the second quarter compared to 2012 include:

- Alberta crude oil production averaging 32,151 barrels per day, increasing seven percent primarily due to additional light and medium crude oil production as a result of successful horizontal well performance associated with our current drilling program;
- Generating Operating Cash Flow, net of capital investment of $231 million, an increase of nine percent from 2012;
- $46 million of previously capitalized E&E costs related to certain tight oil exploration assets were recorded to exploration expense; and
- $63 million of pre-exploration expense.

As part of our strategic plan, we look for opportunities to enhance our portfolio in areas where we may apply our core competencies in crude oil development. Costs incurred prior to obtaining the legal right to explore (pre-exploration) are expensed. As a result of our evaluation of a crude oil exploration opportunity, $63 million of pre-exploration expense was recorded in the quarter.

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability has been established are capitalized as E&E assets. If a field, area or project is determined to no longer be technically feasible or commercially viable and we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

In the second quarter of 2013, $46 million (2012 – $68 million) of previously capitalized E&E costs related to certain conventional tight oil exploration assets were recognized as exploration expense.

Total exploration cost for 2013 was $109 million (2012 – $68 million).

In the first quarter of 2013, Management decided to launch a public sales process to divest our Lower Shaunavon and certain of our Bakken properties in Saskatchewan. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. The Lower Shaunavon property had crude oil production averaging 4,236 barrels per day year-to-date in 2013 (2012 – 4,115 barrels per day) and the Bakken properties for sale had crude oil production averaging 695 barrels per day year-to-date in 2013 (2012 – 1,427 barrels per day).

In June 2013, we entered into a purchase and sale agreement with an unrelated third party, to sell our Lower Shaunavon asset. The sale was completed in July 2013 for proceeds of $240 million plus closing adjustments. As at June 30, 2013, an impairment loss of $57 million was recorded as additional DD&A. The sale does not include our Bakken assets, which we continue to market.

Conventional – Crude Oil

Financial Results

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Gross Sales	**414**	365	**803**	819
Less: Royalties	**39**	38	**74**	92
Revenues	**375**	327	**729**	727
Expenses				
Transportation and Blending	**41**	31	**81**	69
Operating	**81**	67	**165**	146
Production and Mineral Taxes	**9**	8	**18**	17
(Gain) Loss on Risk Management	**(7)**	(7)	**(21)**	-
Operating Cash Flow	**251**	228	**486**	495
Capital Investment	**130**	122	**320**	338
Operating Cash Flow Net of Related Capital Investment	**121**	106	**166**	157

Production

(barrels per day)	Three Months Ended June 30, 2013	Percent Change	2012	Six Months Ended June 30, 2013	Percent Change	2012
Heavy Oil						
Alberta	**16,284**	**4%**	15,703	**16,497**	**2%**	16,163
Light and Medium Oil						
Alberta	**14,976**	**11%**	13,532	**15,155**	**15%**	13,215
Saskatchewan	**21,161**	**(6)%**	22,617	**22,162**	**(4)%**	23,065
NGLs	**950**	**(4)%**	987	**961**	**(9)%**	1,061
	53,371	**1%**	52,839	**54,775**	**2%**	53,504

Three Months Ended June 30, 2013 Compared to June 30, 2012

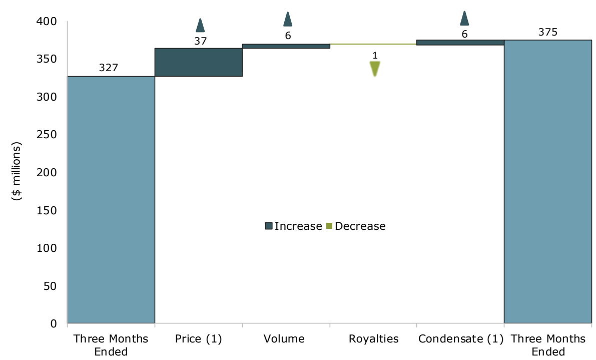
Revenue Variance

Pricing

In the second quarter our average crude oil sales price increased 11 percent to $81.38 per barrel consistent with the change in crude oil benchmark prices and associated differentials.

Production

Our crude oil production was higher in the second quarter primarily due to an increase in light and medium crude oil production in Alberta, as a result of successful horizontal well performance related to our current drilling program. In the second quarter, crude oil production in Alberta increased seven percent to an average of 32,151 barrels per day, while production in Saskatchewan decreased six percent to an average of 21,220 barrels per day, as a result of the reduction in capital spending directed towards our Bakken and Lower Shaunavon drilling program.



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Royalties

Royalties increased by $1 million in the quarter, as a result of higher crude oil prices. The effective crude oil royalty rate in the second quarter for the Conventional segment was 10.7 percent (2012 – 11.7 percent). Most of our crude oil production in the Conventional segment is located on fee land which results in mineral tax recorded within production and mineral taxes.

Expenses

Transportation and Blending

Transportation and blending costs were $10 million higher for the second quarter. Transportation costs rose $4 million due to the higher cost associated with transporting our growing light and medium crude oil production by rail. During the quarter we transported approximately 7,900 barrels per day by rail to the East Coast and the U.S. (2012 – 2,300 barrels per day). The overall cost of condensate used in blending increased $6 million as a result of higher condensate volumes and prices.

Operating

In the second quarter of 2013 operating costs of $81 million were predominantly composed of workforce, workover activities, and electricity. Compared to the second quarter of 2012, operating costs increased $14 million primarily due to higher workforce costs related to the strategic redeployment of workforce away from natural gas activities to focus on crude oil activities, and higher electricity costs as a result of increased market prices.

Risk Management

Risk management activities in the second quarter resulted in realized gains of $7 million (2012 – realized gains of $7 million) consistent with our contract prices exceeding the average benchmark prices.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow, net of capital investment increased by $15 million, or 14 percent, in the second quarter due to higher Operating Cash Flow being partially offset by an $8 million increase in capital investment.

Six Months Ended June 30, 2013 Compared to June 30, 2012

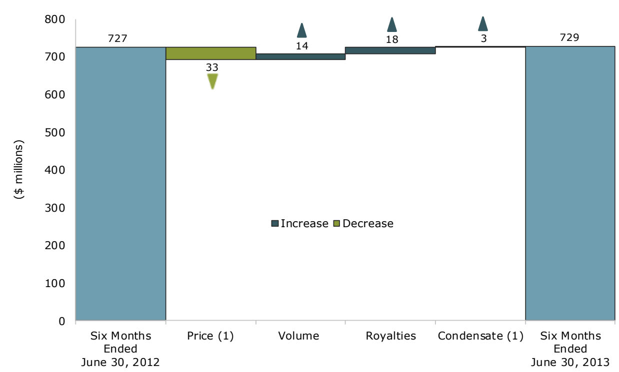
Revenue Variance

Pricing

In the first six months of the year our average crude oil sales price decreased four percent to $76.58 per barrel consistent with the change in crude oil benchmark prices and associated differentials.

Production

Our crude oil production increased primarily due to higher light and medium crude oil production in Alberta from better horizontal well performance associated with our current drilling program. Crude oil production in Alberta increased seven percent to an average of 32,554 barrels per day while production in Saskatchewan decreased four percent to an average of 22,221 barrels per day as a result of the reduction in capital spending directed towards our Bakken and Lower Shaunavon drilling program.



(1) *Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.*

Royalties

Royalties decreased $18 million largely due to lower royalties in Weyburn as a result of lower realized crude oil prices. The effective crude oil royalty rate during the first six months of the year was 10.4 percent (2012 – 12.7 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $12 million in the first six months of the year. Transportation costs rose $9 million due to the higher cost associated with transporting our growing light and medium crude oil production by rail. During the first half of 2013, we transported approximately 6,800 barrels per day by rail to the East Coast and the U.S. (2012 – 1,400 barrels per day). The overall cost of condensate used in blending increased $3 million as a result of utilizing higher condensate volumes partially offset by lower prices.

Operating

In the first six months of the year, operating costs were predominantly composed of workforce, workover activities, and electricity. Operating costs rose $19 million as compared to 2012, primarily due to higher workforce costs, rising electricity costs, as discussed above, and workovers associated with high return well optimizations that have helped mitigate production declines.

Risk Management

Risk management activities resulted in realized gains of $21 million (2012 – no realized gains or losses), consistent with our contract prices exceeding the average benchmark prices.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow, net of capital investment increased by $9 million due to a reduction in capital investment of $18 million, offset by lower Operating Cash Flow.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Gross Sales	**163**	99	**317**	234
Less: Royalties	**2**	1	**4**	3
Revenues	**161**	98	**313**	231
Expenses				
Transportation and Blending	**4**	5	**11**	11
Operating	**54**	48	**105**	102
Production and Mineral Taxes	**-**	1	**1**	2
(Gain) Loss on Risk Management	**(9)**	(68)	**(27)**	(124)
Operating Cash Flow	**112**	112	**223**	240
Capital Investment	**4**	7	**12**	22
Operating Cash Flow Net of Related Capital Investment	**108**	105	**211**	218

Three Months Ended June 30, 2013 Compared to June 30, 2012

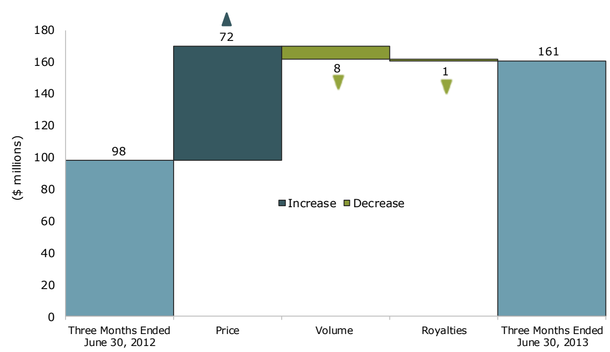
Revenues Variance

Pricing

In the second quarter our average natural gas sales price increased $1.58 per Mcf to $3.50 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased nine percent to 512 MMcf per day in the second quarter primarily due to expected natural declines.



Royalties

Royalties increased in the second quarter as a result of higher prices, despite production declines. The average royalty rate in the second quarter was 1.2 percent (2012 – 1.0 percent). Most of our natural gas production in the Conventional segment is located on fee land where we hold mineral rights which results in mineral tax being recorded within production and mineral taxes.

Expenses

Transportation

Transportation costs decreased $1 million as a result of lower production volumes.

Operating

In the three months ended June 30, 2013, our operating expenses were composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses increased $6 million due to an increase in the cost of electricity and repairs and maintenance, despite the reduction in natural gas production.

Risk Management

Risk management activities resulted in realized gains in the second quarter of $9 million (2012 – realized gains of $68 million), consistent with our contract prices exceeding the average benchmark price.

Operating Cash Flow, Net of Capital Investment

Our Conventional natural gas assets generate significant Operating Cash Flow with minimal capital investment. Operating Cash Flow, net of capital investment increased three percent to $108 million in the second quarter due to higher revenues as a result of a rise in realized sales prices, partially offset by lower realized risk management gains and lower production volumes.

Six Months Ended June 30, 2013 Compared to June 30, 2012

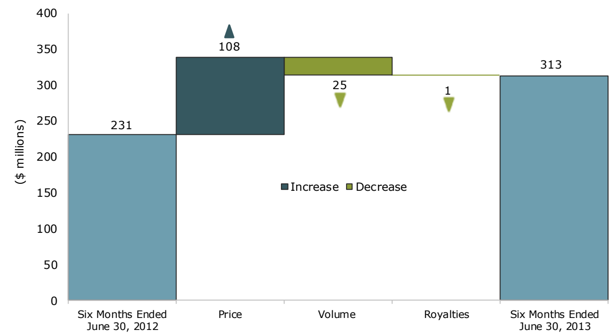
Revenue Variance

Pricing

In the first six months of the year, our average natural gas sales price increased $1.15 per Mcf to $3.37 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased 11 percent to 518 MMcf per day in the first six months of the year, primarily due to expected natural declines.



Royalties

Royalties increased in the first six months of the year, as a result of higher prices, despite declines in production. The average royalty rate was 1.4 percent in the first six months of the year (2012 – 1.4 percent).

Expenses

Transportation

Transportation costs remained flat year-to-date with higher pipeline rates offset by lower production volumes.

Operating

For the six months ended June 30, 2013, our operating expenses were composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses increased $3 million due to a rise in the cost of electricity despite the reduction in natural gas production.

Risk Management

Risk management activities resulted in year-to-date realized gains of $27 million (2012 – realized gains of $124 million) consistent with our contract prices exceeding the average benchmark price.

Operating Cash Flow, Net of Capital Investment

Operating Cash Flow from natural gas net of capital investment decreased $7 million to $211 million, due to lower Operating Cash Flow, as a result of lower realized risk management gains and a drop in production volumes, partially offset by a reduction in capital investment.

Conventional – Capital Investment (1)

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Crude Oil	**130**	122	**320**	338
Natural Gas	**4**	7	**12**	22
	134	129	**332**	360

(1) Includes expenditures on PP&E and E&E assets.

Capital investment in our Conventional segment focused on crude oil opportunities. In the three and six months ended June 30, 2013, capital was invested primarily in our tight oil drilling programs in Alberta and in drilling and facilities work at Weyburn. Spending on natural gas activities continues to be managed in response to the low price natural gas environment.

Conventional Drilling Activity

	Six Months Ended June 30,	
(net wells, unless otherwise stated)	**2013**	2012
Crude Oil	**64**	114
Recompletions	**317**	579
Gross Stratigraphic Test Wells	**13**	7

Crude oil wells drilled reflect the ongoing development of our Conventional properties. Well recompletions are mostly related to low-risk Alberta coal bed methane development that continues to deliver acceptable rates of return.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. Our Refining and Marketing segment allows us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated strategy provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to our refineries. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

Significant factors related to our Refining and Marketing segment in the second quarter, compared to 2012, include:

- Operating Cash Flow decreasing nine percent to $320 million due to lower crude oil volumes processed as a result of an unplanned hydrocracker outage, increased refinery crude oil feedstock costs from narrowing Canadian heavy and U.S. inland crude oil discounts and higher utility costs from rising natural gas prices, partially offset by higher market crack spreads; and
- Our refineries processing 439,000 barrels per day of crude oil, including 230,000 barrels per day of heavy crude oil, resulting in 457,000 barrels per day of refined product output, a decrease as a result of an unplanned hydrocracker outage.

Refinery Operations (1)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	**2013**	2012
Crude Oil Capacity (2) (Mbbls/d)	**457**	452	**457**	452
Crude Oil Runs (Mbbls/d)	**439**	451	**428**	448
Heavy Oil	**230**	229	**214**	214
Light/Medium	**209**	222	**214**	234
Crude Utilization (percent)	**96**	100	**94**	99
Refined Products (Mbbls/d)	**457**	473	**448**	469
Gasoline	**221**	239	**223**	235
Distillate	**145**	154	**139**	154
Other	**91**	80	**86**	80

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity of Wood River increased effective January 1, 2013.

On a 100 percent basis, our refineries have a capacity of approximately 457,000 barrels per day of crude oil and 45,000 barrels per day of NGLs, including processing capability to refine between 235,000 to 255,000 barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy oil production.

In the three and six months ended June 30, 2013, the amount of crude oil processed dropped three and four percent, respectively, as a result of planned maintenance in the first quarter and an unplanned hydrocracker outage in June. Heavy crude oil processed remained flat.

Our crude utilization represents the percentage of crude oil, heavy and other, that is processed in our refineries relative to the total capacity. The amount of heavy crude oils processed, such as WCS and CDB, is dependent on the quality of available crude oils with the total crude input slate being optimized to maximize economic benefit.

Total refined product output decreased by three and four percent in the second quarter and year-to-date, respectively, with the proportion of gasoline, distillate and other refined products remaining relatively the same. The change was primarily due to planned maintenance and an unplanned hydrocracker outage.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Revenues	**3,078**	2,962	**6,024**	5,954
Purchased Product	**2,616**	2,508	**4,893**	5,097
Gross Margin	**462**	454	**1,131**	857
Expenses				
Operating	**138**	123	**275**	253
(Gain) Loss on Risk Management	**4**	(20)	**8**	(14)
Operating Cash Flow	**320**	351	**848**	618
Capital Investment	**26**	24	**51**	22
Operating Cash Flow, Net of Capital Investment	**294**	327	**797**	596

Three Months Ended June 30, 2013 Compared to June 30, 2012

Gross Margin

The gross margin for the Refining and Marketing segment increased $8 million, or two percent in the second quarter, as a result of increased refined product prices, partially offset by lower volumes of crude oil processed as a result of an unplanned hydrocracker outage, and higher crude oil feedstock costs resulting from narrowing Canadian heavy and U.S. inland crude discounts.

As part of the U.S. Environmental Protection Agency's ("EPA") Renewable Fuel Standards, refineries in the U.S. are obligated to blend renewable fuels (such as ethanol) into petroleum-based motors fuel products at rates determined by the EPA. To the extent they do not, refineries must purchase credits, referred to as Renewable Identification Numbers ("RINs"), in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into their motor fuel products and consequently we are obligated to purchase RINs in the open market. Since the beginning of 2013, the cost of RINs has increased significantly due primarily to current and impending increases to the EPA's mandated blending quotas. Despite the recent increase in RIN prices these costs remain a minor component of our total refinery feedstock costs.

Operating

Total operating costs for the three months ended June 30, 2013 consist mainly of labour, maintenance, utilities and supplies. Operating costs were higher by $15 million, or 12 percent due to higher utilities as natural gas prices have increased.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment decreased $31 million, or nine percent, as a result of lower volumes of crude oil processed and increased feedstock costs, offset by higher market crack spreads.

Six Months Ended June 30, 2013 Compared to June 30, 2012

Gross Margin

The gross margin for the Refining and Marketing segment increased $274 million, or 32 percent in the first six months, primarily due to lower refinery feedstock costs as inland crude discounts, in particular Canadian heavy crude oil, were wider in early 2013, partially offset by lower crude rates due to planned maintenance and an unplanned hydrocracker outage. Refined product prices were relatively flat in the first six months of the year compared to 2012.

Operating

Total operating costs for the six months ended June 30, 2013 consist mainly of labour, maintenance, utilities and supplies. Operating costs were higher by $22 million, or nine percent due to planned maintenance activities in the first quarter and higher utilities as natural gas prices have increased.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment increased $230 million, or 37 percent year-to-date due to strong refining margins, resulting from discounted refinery crude oil feedstock costs and improved market crack spreads, partially offset by lower refined product output from planned maintenance in the first quarter and an unplanned hydrocracker outage in the second quarter.

Refining and Marketing – Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2013**	2012	**2013**	2012
Wood River Refinery	**13**	14	**26**	6
Borger Refinery	**13**	10	**25**	16
	26	24	**51**	22

Capital expenditures for the year were focused on capital maintenance and projects improving refinery reliability and safety. In the first quarter of 2012, we recognized Illinois tax credits of $14 million related to capital expenditures incurred at the Wood River Refinery in prior periods, which reduced capital investment for the six months ended June 30, 2012.

Future capital investment may include heavy crude debottlenecking opportunities at our Wood River Refinery.

DD&A

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Oil Sands	**150**	110	**298**	225
Conventional	**277**	222	**533**	458
Refining and Marketing	**33**	35	**65**	73
Corporate and Eliminations	**20**	12	**39**	23
	480	379	**935**	779

Oil Sands DD&A in the second quarter increased $40 million (year-to-date – $73 million increase) due to additional sales volumes and higher DD&A rates for all of our properties. DD&A rates averaged 15 percent higher due to higher future development costs associated with total proved reserves.

DD&A in the Conventional segment was $55 million higher in the second quarter (year-to-date – increased $75 million) primarily due to a $57 million impairment loss related to our Lower Shanuavon assets which are held for sale. In the six months ended June 30, 2013, the increase in the average DD&A rate was 17 percent from 2012, due to lower proved reserves. The increases were partially offset by reduced natural gas sales volumes.

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. The increase in 2013 is due to the depreciation of our new office space leaseholds which commenced in October 2012.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating 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 the long-term power purchase contract. The unrealized gains on risk management were $26 million for the second quarter (2012 – unrealized gains of $169 million) and year-to-date unrealized losses were $204 million (2012 – unrealized gains of $233 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative and financing activities.

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
General and Administrative	**82**	56	**165**	149
Finance Costs	**124**	111	**247**	224
Interest Income	**(23)**	(27)	**(50)**	(56)
Foreign Exchange (Gain) Loss, net	**96**	25	**148**	9
(Gain) Loss on Divestitures	**-**	(1)	**-**	(1)
Other (Income) Loss, net	**(2)**	1	**-**	(4)
	277	165	**510**	321

Three and Six Months Ended June 30, 2013 Compared to June 30, 2012

General and Administrative

General and administrative expenses increased $26 million in the quarter primarily due to an increase in office rent as well as staffing cost to support our growing operations and a higher long-term incentive recovery in 2012. For the six months ended June 30, 2013, the increase of $16 million was also due to higher rental and staffing costs, offset by lower long-term incentive costs.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. In the second quarter, finance costs were $13 million higher (year-to-date – $23 million increase) than 2012 due to the interest incurred on the US$1.25 billion of senior unsecured notes issued on August 17, 2012, offset by lower interest incurred on the Partnership Contribution Payable as the balance continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the second quarter was 5.3 percent (2012 – 5.2 percent) and for the six months ended June 30, 2013 was 5.3 percent (2012 – 5.3 percent).

Interest Income

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. Interest income for the three and six months ended June 30, 2013 decreased by $4 million and $6 million, respectively, consistent with lower interest earned on the Partnership Contribution Receivable as the balance continues to be collected.

Foreign Exchange

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Unrealized Foreign Exchange (Gain) Loss	**84**	9	**134**	(22)
Realized Foreign Exchange (Gain) Loss	**12**	16	**14**	31
	96	25	**148**	9

The majority of unrealized losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at June 30, 2013, partially offset by unrealized gains on our U.S. dollar denominated Partnership Contribution Receivable.

Income Tax Expense

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Current Tax				
Canada	**57**	21	**87**	83
United States	**4**	13	**58**	25
Total Current Tax	**61**	34	**145**	108
Deferred Tax	**40**	204	**79**	298
	101	238	**224**	406
Effective Tax Rate	**36%**	38%	**39%**	33%

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes. 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, variations in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

Our effective tax rate also reflects the application of the relevant statutory tax rates to income from Canadian and U.S. sources. Our effective tax rate for the second quarter is comparable to 2012. Our year-to-date effective tax rate increased compared to 2012 due to a higher proportion of net income attributable to U.S. sources.

In the three and six months ended June 30, 2013, our current tax expense has increased in comparison to 2012 due to higher Operating Cash Flow in Canada and the anticipated utilization in 2013 of all remaining U.S. federal net operating losses.

Deferred income tax expense for the second quarter and year-to-date in 2013, is lower than in 2012 primarily because of lower levels of net income.

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.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Net Cash From (Used In)				
Operating Activities	**828**	968	**1,723**	1,633
Investing Activities	**(803)**	(788)	**(1,706)**	(1,620)
Net Cash Provided (Used) Before Financing Activities	**25**	180	**17**	13
Financing Activities	**(183)**	(230)	**(349)**	(92)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**5**	(1)	**(3)**	(7)
Increase (Decrease) in Cash and Cash Equivalents	**(153)**	(51)	**(335)**	(86)

Operating Activities

Cash from operating activities was $140 million lower in the second quarter (year-to-date – increase of $90 million). The second quarter decline was mainly due to the $82 million decrease in Cash Flow as discussed in the Financial Results section of this MD&A, and the net change in non-cash working capital. The year-to-date increase was impacted by the net change in non-cash working capital.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $918 million at June 30, 2013 compared to $1,043 million at December 31, 2012. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

Cash used in investing activities in the second quarter was $15 million higher (year-to-date – increase of $86 million) than in 2012. These increases were primarily due to an increase in capital expenditures.

Financing Activities

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 finally to growth capital. In the second quarter, we paid a dividend of $0.242 per share, an increase of 10 percent from 2012 (2012 – $0.22 per share). Total dividend payments year-to-date are $367 million (2012 – $332 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

In the second quarter, cash flow used in financing activities decreased $47 million due to higher repayments on short-term borrowings in the second quarter of 2012, partially offset by an increase in dividends. In the six months ended June 30, 2013, cash flow used in financing activities rose $257 million as a result of less short-term borrowings being issued in 2013 as compared to 2012 and the increase in dividends.

Our long-term debt was $4,948 million at June 30, 2013 with no principal payments due until September 2014 (US$800 million). The $269 million change in long-term debt from December 31, 2012 was related to foreign exchange. We had cash and cash equivalents of $825 million at June 30, 2013.

Available Sources of Liquidity

($ millions)	Amount	Term
Cash and Cash Equivalents	**825**	**Not Applicable**
Committed Credit Facility	**3,000**	**November 2016**
Canadian Base Shelf Prospectus [(1)]	**1,500**	**June 2014**
U.S. Base Shelf Prospectus [(1)]	**US$2,000**	**July 2014**

(1) Availability is subject to market conditions.

A portion of our future cash requirements may be funded through management of our asset portfolio. In the first quarter of 2013, Cenovus decided to launch a public sales process to divest its Lower Shaunavon and certain of its Bakken properties in Saskatchewan. In the second quarter, we entered into an agreement to sell the Shaunavon assets for proceeds of $240 million plus closing adjustments and closed the sale on July 3, 2013. We continue to market our Bakken properties.

On May 9, 2013, we amended our U.S. base shelf prospectus for senior unsecured notes to increase the total capacity from US$2.0 billion to US$3.25 billion. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at June 30, 2013, we have unused capacity of US$2.0 billion, the availability of which is dependent on market conditions.

As at June 30, 2013, we are in compliance with all of the terms of our debt agreements.

Financial Metrics

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 Capitalization as Debt plus Shareholders' Equity. We define trailing 12-month Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	June 30, 2013	December 31, 2012
Debt to Capitalization	**33%**	32%
Debt to Adjusted EBITDA (times)	**1.2x**	1.1x

We continue to have long-term targets for 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. At June 30, 2013, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.

At June 30, 2013, our financial position remained relatively consistent with the end of 2012 as measured by our Debt to Capitalization and Debt to Adjusted EBITDA. Additional information regarding our financial metrics and capital structure can be found in the notes to the interim Consolidated Financial Statements.

Outstanding Share Data and Stock-based Compensation Plans

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 June 30, 2013, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of Cenovus. Options issued by Cenovus prior to February 24, 2011, have associated tandem stock appreciation rights ("TSARs") and options issued after February 24, 2011 have associated net settlement rights ("NSRs").

In addition to its Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan and two Deferred Share Unit ("DSU") Plans. PSUs are whole share units which, upon vesting, entitle the holder to receive either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. DSUs vest immediately and are equivalent in value to a Cenovus common share on the date of redemption.

Our stock options are measured at fair value using the Black-Scholes-Merton valuation model and other stock-based compensation plans are measured at fair value based on the market value of our common shares. The fair value of our TSARs, PSUs and DSUs are measured at each reporting date and therefore are sensitive to fluctuations in our common share price. The fair value of NSRs is determined at the date of grant and is not re-measured at each reporting date. As NSRs become a higher proportion of our long-term incentive grants, our long-term incentive costs will become less sensitive to common share price fluctuations. The weighted average remaining contractual life of the TSARs, NSRs and PSUs are 1.60, 5.91 and 1.75 years, respectively. See the notes to the interim and annual Consolidated Financial Statements for details of our stock-based compensation plans.

Total Outstanding Common Shares and Stock-based Compensation Plans

(thousands of units)	June 30, 2013
Common Shares	**755,828**
Stock Options	
NSRs	**25,828**
TSARs	**8,106**
Cenovus Replacement TSARs (held by Encana Employees)	**2,672**
Encana Replacement TSARs (held by Cenovus Employees)	**4,166**
Other Stock-based Compensation Plans	
PSUs	**5,813**
DSUs	**1,172**

Contractual Obligations and Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements, debt, future building leases, marketing agreements and capital commitments. 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 interim and annual Consolidated Financial Statements.

In the first six months of the year, Cenovus entered into various firm transportation agreements totaling approximately $10 billion. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement and will help align our future transportation requirements within our anticipated production growth.

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 legal claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with our 2012 annual MD&A.

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. Our exposure to liquidity risk, safety risk, transportation restrictions, capital project execution and operating risk, reserves replacement risk, environmental risk and regulatory risk has not changed substantially since December 31, 2012.

A description of the risk factors and uncertainties 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,

2012. The following provides an overview of our commodity price risk management activities and the effect of our risk management position on earnings for the three and six months ending June 30, 2013.

Commodity Price Risk

Fluctuations in commodity prices create volatility in our financial performance. Commodity prices are influenced by a number of factors including global and regional supply and demand, transportation constraints and alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

We manage our commodity price exposure through a combination of integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. We further reduce our exposure to commodity price risk through the use of various financial instruments and select physical contracts.

The details of these financial instruments as at June 30, 2013 are disclosed in the notes to the interim Consolidated Financial Statements. The financial impact is summarized below.

Financial Impact of Risk Management Activities

	Three Months Ended June 30,					
	2013			2012		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	11	21	32	26	261	287
Natural Gas	8	6	14	75	(97)	(22)
Refining	(4)	(3)	(7)	17	5	22
Power	5	2	7	(2)	-	(2)
Gain (Loss) on Risk Management	20	26	46	116	169	285
Income Tax Expense	4	5	9	32	43	75
Gain (Loss) on Risk Management, after-tax	16	21	37	84	126	210

	Six Months Ended June 30,					
	2013			2012		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	54	(169)	(115)	-	291	291
Natural Gas	27	(36)	(9)	135	(61)	74
Refining	(8)	(1)	(9)	12	8	20
Power	5	2	7	(2)	(5)	(7)
Gain (Loss) on Risk Management	78	(204)	(126)	145	233	378
Income Tax Expense (Recovery)	18	(52)	(34)	38	59	97
Gain (Loss) on Risk Management, after-tax	60	(152)	(92)	107	174	281

In the three and six months ended June 30, 2013, management of commodity price risk resulted in realized gains on crude oil, natural gas and power financial instruments as our fixed contract prices settled above the market commodity prices. In the second quarter, we recognized unrealized gains on our crude oil and natural gas financial instruments as a result of the decrease in forward commodity prices, partially offset by the narrowing of forward light/heavy differentials, compared to prices at the end of the prior quarter, and the realization of settled positions. For the six months ended June 30, 2013 we recognized unrealized losses on our crude oil financial instruments as a result of the realization of settled positions, the narrowing of forward light/heavy differentials, partially offset by the decrease in forward commodity prices for crude oil, compared to prices at the end of the prior year. Financial instruments undertaken within our refining segment by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

For more details regarding our critical accounting judgments, estimates and accounting policies the following should be read in conjunction with our 2012 annual MD&A.

We are required to make judgments, estimates and assumptions 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 details on the basis of presentation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

Critical Accounting Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in Cenovus's annual and interim Consolidated Financial Statements and accompanying notes. On January 1, 2013, as required, we adopted the standards related to joint arrangements, consolidations and associates, which required critical judgments. See discussion below under Joint Arrangements, Consolidation, Associates and Disclosures for details. Further information on our critical accounting judgments in applying accounting policies can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. There have been no changes to our key sources of estimation uncertainty for the first six months of 2013. Further information on our key sources of estimation uncertainty can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

Changes in Accounting Policies

Joint Arrangements, Consolidation, Associates and Disclosures

As disclosed in the Consolidated Financial Statements, effective January 1, 2013, Cenovus adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to IAS 28, "*Investments in Associates and Joint Ventures*" ("IAS 28").

Cenovus reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees.

Under IFRS 11, interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Cenovus performed a comprehensive review of its interests in other entities and identified two individually significant interests, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), for which it shares joint control. Previously, Cenovus accounted for these jointly controlled entities using proportionate consolidation.

Cenovus reviewed these joint arrangements considering their structure, the legal forms of any separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of Cenovus's accounting policy under IFRS 11 requires judgment in determining the classification of these joint arrangements. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements have been classified as joint operations under IFRS 11 and Cenovus's share of the assets, liabilities, revenues and expenses have been recognized in our interim Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, Cenovus considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially, on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnerships. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and as such are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

There has been no impact on the recognized assets, liabilities and comprehensive income of Cenovus with the application of these standards.

Employee Benefits

As disclosed in the Consolidated Financial Statements, effective January 1, 2013, Cenovus adopted, as required, International Accounting Standard ("IAS") 19 "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). Cenovus applied the standard retrospectively, as required, and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

The amendments require the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor approach' previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through comprehensive income. In addition, Cenovus replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability measured by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period. Interest expense and interest income on net post-employment benefit liabilities and assets continue to be recognized in net earnings.

IAS 19R requires termination benefits to be recognized at the earlier of when the entity can no longer withdraw an offer of termination benefits or recognizes any restructuring costs. This amendment had no impact on the Consolidated Financial Statements.

The impact on adoption of IAS 19R was not material and is shown below:

Consolidated Statements of Earnings and Comprehensive Income

($ millions)	Three Months Ended June 30, 2012	Six Months Ended June 30, 2012	Year Ended December 31, 2012
Increase (Decrease) due to:			
Net Earnings	1	1	2
Other Comprehensive Income	(2)	(2)	(4)

Consolidated Balance Sheets

($ millions)	December 31, 2012	January 1, 2012
Increase (Decrease) due to:		
Net Defined Benefit Liability [(1)]	32	30
Deferred Income Taxes	(8)	(8)
Shareholders' Equity	(24)	(22)

(1) Composed of the defined benefit pension and other post-employment benefit plans.

Fair Value Measurement

Effective January 1, 2013, Cenovus adopted, as required, IFRS 13, "*Fair Value Measurement*" ("IFRS 13") and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to Cenovus's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013.

Presentation of Items in Other Comprehensive Income

Effective January 1, 2013, Cenovus applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within other comprehensive income ("OCI") to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to other comprehensive income or comprehensive income.

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2013, Cenovus complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. Refer to the interim Consolidated Financial Statements for the additional disclosure. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets.

Future Accounting Pronouncements

In May 2013, the IASB released an amendment to IAS 36 "*Impairment of Assets*". This amendment requires entities to disclose the recoverable amount of an impaired Cash Generating Unit ("CGU"). The amendment is effective January 1, 2014. Early adoption is permitted.

A description of other standards and interpretations that will be adopted by Cenovus in future periods can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2012.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") in the three months ended June 30, 2013 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

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. Our Corporate Responsibility ("CR") policy continues to drive our commitments, strategy and reporting, and enables alignment with our business objectives and processes. This policy and our CR report are available on our website at cenovus.com.

In June 2013, we were recognized for the third time by Corporate Knights Magazine as one of Canada's Best 50 Corporate Citizens. Cenovus was also recognized as one of Canada's Top 50 Socially Responsible Corporations for a second year in a row by Maclean's/Sustainalytics. The recognition of our commitment to corporate responsibility reaffirms Cenovus's efforts to balance economic, governance, social and environmental performance. Cenovus is also a member of the Dow Jones Sustainability World and North America Indices.

OUTLOOK

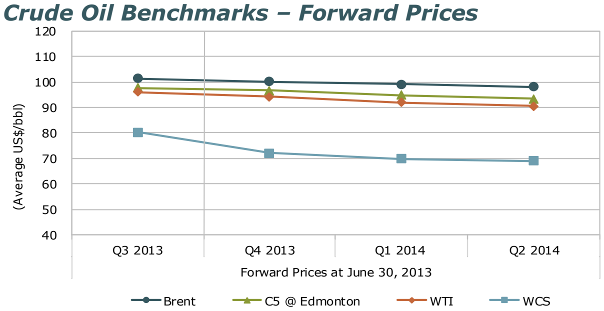
We continue to move forward on our 10 year strategic plan targeting net oil sands bitumen production of approximately 435,000 barrels per day and total net oil production of approximately 525,000 barrels per day by the end of 2023. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Grand Rapids and Telephone Lake. We will 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 with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

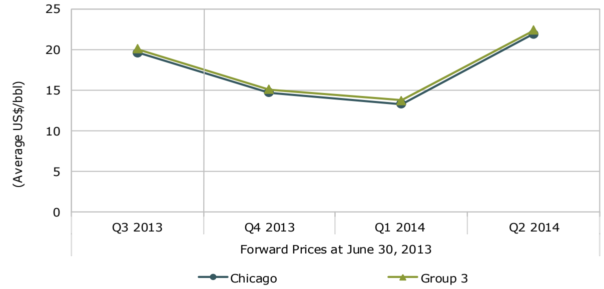
- The general outlook for crude oil prices will continue to be tied to global economic growth and production interruptions. The consensus is for improvement in global economic growth in the second half of 2013 and in 2014. Short-term prices are likely to remain volatile and be influenced by changing market expectations;
- Brent-WTI differentials are expected to continue to narrow over the second half of 2013 as new pipeline capacity is added to move crude oil from Cushing to the U.S. Gulf Coast markets. While the differential is expected to narrow, WTI prices should remain at a discount to Brent prices;
- We expect WCS prices to weaken relative to U.S. Gulf Coast and WTI pricing. With several new oil sands projects starting up over the next several months, inland heavy crude oil supply should increase and push the pipeline system back into a constrained situation.

Crude Oil Benchmarks – Forward Prices



- Refining crack spreads have already materially softened from elevated levels earlier in the quarter as Chicago-area refinery maintenance comes to an end. Refining crack spreads will continue to remain towards the lower end of the range experienced over the past couple of years as inland crude discounts narrow. Refiners processing Western Canadian Sedimentary Basin crude oil should continue to see strong margins. Compared to those processing WTI crudes who will likely see softening margins as the Brent-WTI differential narrows; and
- Natural gas prices are expected to remain near the US$4/MMBtu through the summer but will be affected by summer temperatures and the pace of supply additions. Recent infrastructure additions, which enable new supply to reach market, are not expected to increase prices in the coming quarter. This should allow for further strengthening of prices by year end.

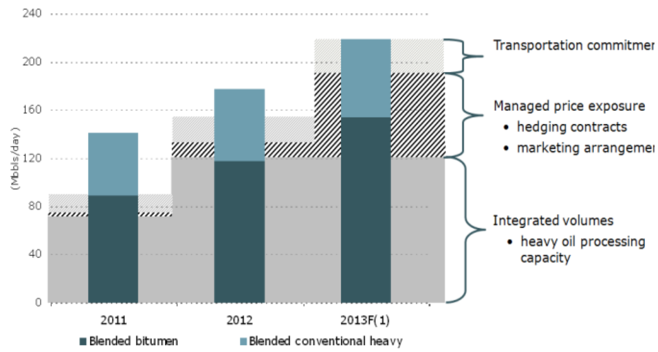
Refining 3-2-1 Crack Spread Benchmarks – Forward Prices



While we expect to see volatility in crude prices, we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy crudes. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – protecting our upstream crude prices from downside risk by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – protecting our upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Protection Against Canadian Crude Oil Congestion



(1) Expected net production capacity.

Update on Key Priorities for 2013

Market Access

We are focused on near and mid-term strategies to broaden market access for Canadian oil. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. We anticipate increasing our rail shipping capacity for oil to approximately 10,000 barrels per day by the end of 2013, committing to industry transportation projects as well as new and expanded market development initiatives for our crude oil. In the second quarter of 2013, we transported approximately 7,900 barrels per day by rail, allowing us to realize higher prices on our crude oil and diversify our customer base. We also entered into $7 billion of new pipeline commitments (some of which include amounts for projects awaiting regulatory approval) to align our future transportation requirements with our anticipated growth.

Long-term Cost Structures

We have a track record of cost efficiency. To continue to meet our business plan, we must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we have a number of opportunities to improve our cost efficiency by further leveraging our supply chain management to improve capital and operating costs.

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing competitive pressures within the industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section in our annual MD&A. We also direct our readers to review the guidance for 2013 that we published on our website, cenovus.com, in connection with our December 12, 2012 news release and updates to that guidance in the July 24, 2013 news release.

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" or "F", "target", "project", "could", "focus", "vision", "goal", "proposed", "scheduled", "outlook", "potential", "projected", "objectives", "may", "strategy" 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, projections contained in our 2013 guidance, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, broadening market access, improving cost structure, 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 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 disclosed in our current guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; estimates 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.

We updated our guidance for 2013, published on our website, cenovus.com, and provided details of the events and circumstances that led to the update in our July 24, 2013 news release.

For the period 2014 to 2023 assumptions include Brent US$100.00-US$110.00; WTI of US$96.00-US$106.00/bbl; Western Canada Select of C$71.00-C$91.00/bbl; NYMEX of US$4.50-US$4.75/MMBtu; AECO of C$3.89-C$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$15.00; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 780 million.

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; the 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; our ability to maintain our relationship with our partners 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 the regulatory framework in any of the locations in which we operate, 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 interim 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 risk management, see "Risk Management" in this MD&A and in our MD&A for the year ended December 31, 2012. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the year ended December 31, 2012, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

ABBREVIATIONS

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

Crude Oil		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
		GJ	Gigajoule
		CBM	Coal Bed Methane

Other	
TM	Trademark of Cenovus Energy Inc.