MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED JUNE 30, 2014

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated July 29, 2014, should be read in conjunction with our June 30, 2014 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2013 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2013 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of July 29, 2014, unless otherwise indicated. 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&As are 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 approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, 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. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

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 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. This 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 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, 2014, we had a market capitalization of approximately $26 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 (collectively, "crude oil") production in the first six months of 2014 was in excess of 199,000 barrels per day and our average natural gas production was 492 MMcf per day. Our refineries processed an average of 433,000 gross barrels per day of crude oil feedstock into an average of 458,000 gross barrels per day of refined products.

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.

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek, Christina Lake, Narrows Lake, Telephone Lake, Grand Rapids and our conventional 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 through our annual stratigraphic test well drilling program.

We plan to increase our annual net crude oil production, including our conventional oil operations, to more than 500,000 barrels per day. We anticipate the capital investment necessary to achieve this production level will 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 business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Sands

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

	Six Months Ended June 30, 2014		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	55,785	111,570
Christina Lake	50	66,863	133,726
Narrows Lake	50	-	-
Emerging Projects			
Telephone Lake	100	-	-
Grand Rapids	100	-	-

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. They are located in the Athabasca region of northeastern Alberta.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flow. This production 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 oil sands and refining operations and provides cash flow to help fund our growth opportunities.

	Six Months Ended June 30, 2014	
($ millions)	Crude Oil (1)	Natural Gas
Operating Cash Flow (2)	735	275
Capital Investment	412	11
Operating Cash Flow Net of Related Capital Investment	323	264

(1) Includes NGLs.
(2) Non-GAAP measure defined in this MD&A.

We have established crude oil and natural gas producing assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn, heavy oil assets at Pelican Lake and developing tight oil assets in Alberta.

Approximately 70 percent, or 4.5 million net acres, of our conventional land is owned in fee title, which means we own the mineral rights. Where we have working interest production from fee lands, we do not pay a third party royalty, rather we pay mineral tax to the government which is generally lower than royalties paid to mineral interest owners. In addition, a portion of our fee lands are leased to third parties which may give rise to royalty income. Approximately 50 percent of our total conventional production comes from our fee lands.

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)	2014 Gross Nameplate Capacity (Mbbls/d)
Wood River	50	314
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 partially mitigate volatility associated with North American commodity price movements. This segment also includes our 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, 2014
Operating Cash Flow [1]	465
Capital Investment	69
Operating Cash Flow Net of Related Capital Investment	**396**

(1) Non-GAAP measure defined in this MD&A.

Technology and Environment

Technology development, research activities and the environment are playing increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technology with the goals of increasing recoveries from our reservoirs, while reducing the amount of water, natural gas and electricity consumed in our operations, potentially reducing costs and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches. We have a track record of developing innovative solutions that unlock challenging crude oil resources and builds 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. In the first and second quarters of 2014, we paid a dividend of $0.2662 per share, a 10 percent increase from 2013.

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 believe that our goal of doubling our December 2009 net asset value by the end of 2015 is an achievable target.

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

Our results continue to reflect the strength of our integrated approach. In the second quarter, higher upstream Operating Cash Flow was partially offset by lower Operating Cash Flow from Refining and Marketing. Upstream Operating Cash Flow increased 34 percent compared to 2013 due to higher sales prices for crude oil blend and natural gas, as well as increased crude oil production. Crude oil sales prices increased 17 percent mainly due to the 11 percent increase in the Western Canadian Select ("WCS") benchmark price and the weakening of the Canadian dollar. The rise in WCS to US$82.95 per barrel (2013 – US$75.06 per barrel) increased the cost of our heavy crude oil feedstock which, along with declines in market crack spreads, resulted in a 32 percent decrease in Operating Cash Flow from our refining operations.

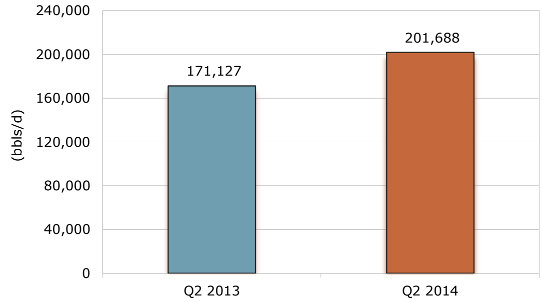
Operational Results for the Second Quarter of 2014 Compared With the Second Quarter of 2013

Total crude oil production in the second quarter averaged 201,688 barrels per day, up 18 percent from 2013.

In the second quarter, crude oil production from our Oil Sands segment averaged 124,827 barrels per day, an increase of 33 percent, primarily driven by higher production at Christina Lake. Average production at Christina Lake was 67,975 barrels per day, a 77 percent increase, as phase E reached nameplate production capacity in the second quarter of 2014.

Foster Creek production averaged 56,852 barrels per day, up three percent and in line with our expectations.

Total Crude Oil Production Volumes



Our Conventional crude oil production averaged 76,861 barrels per day, a slight decline from 2013. The increase in production from successful horizontal well performance in southern Alberta and higher production at Pelican Lake was offset by expected natural declines and the sale of our Lower Shaunavon and Bakken assets in July 2013 and April 2014, respectively. Pelican Lake production averaged 24,806 barrels per day, an increase of four percent, resulting from additional infill wells coming on-stream and an increased response from the polymer flood program.

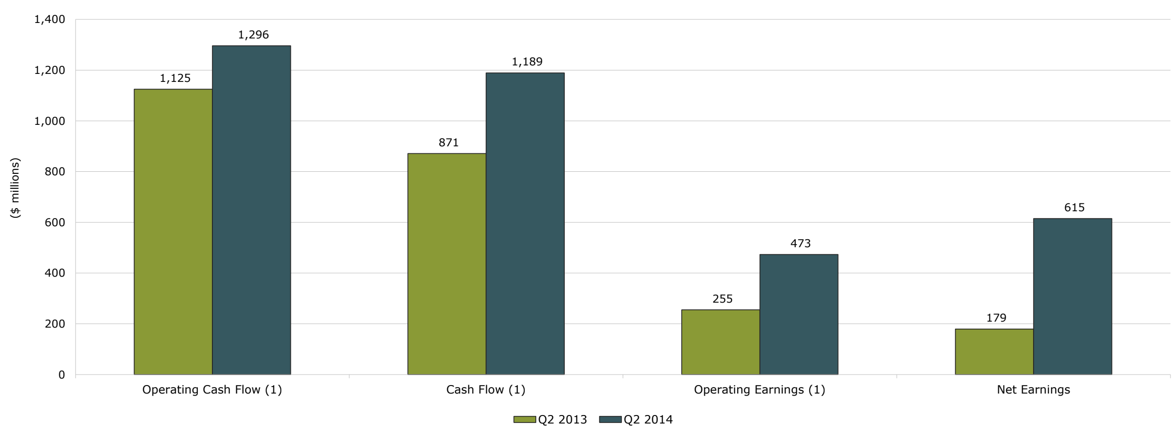
Our refineries processed an average of 466,000 gross barrels per day (2013 – 439,000 gross barrels per day) of crude oil, of which 221,000 gross barrels per day (2013 – 230,000 gross barrels per day) was heavy crude oil. As a result of the optimization of our total crude input slate, there was a decrease in heavy crude oil processed. We produced 489,000 gross barrels per day of refined products, an increase of 32,000 gross barrels per day, or seven percent, as a result of reliable refinery performance in 2014 as compared to an unplanned hydrocracker outage in 2013 and the timing of planned turnarounds and maintenance. The 2014 Borger planned turnaround was completed in the first quarter of 2014 and the 2013 turnaround was completed in the second quarter.

Other significant operational results in the second quarter of 2014 include:

- Commencing circulation steaming at Foster Creek phase F;
- Completing a planned turnaround at Christina Lake phases A and B with minimal impact to production;
- Receiving anticipated regulatory approval for expansion of the Foster Creek development area;
- Closing of the disposition of certain of our Bakken assets for proceeds of $36 million before closing adjustments; and
- Transporting approximately 5,500 barrels per day of crude oil by rail to the U.S., including five unit train shipments.

Financial Results for the Second Quarter of 2014 Compared With the Second Quarter of 2013

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



(1) Non-GAAP measure defined in this MD&A.

Financial highlights for the second quarter of 2014 compared with 2013 include:

Revenues

Revenues of $5,422 million, increasing $906 million or 20 percent as a result of:

- Refining and Marketing revenues increasing $405 million primarily due to the weakening of the Canadian dollar and higher refined product output, partially offset by the decline in refined product prices, consistent with the decrease in Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices, and an increase in revenues from third-party sales of crude oil and natural gas;
- Higher sales prices for crude oil blend and natural gas, consistent with the rise in the WCS and AECO benchmark prices; and
- An increase in blended crude oil sales volumes, consistent with higher production volumes.

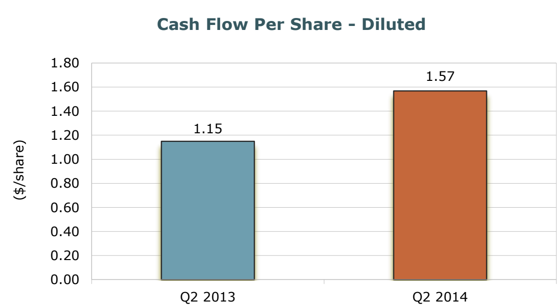
Operating Cash Flow

In the second quarter, Operating Cash Flow was $1,296 million, an increase of $171 million. Upstream Operating Cash Flow increased 34 percent, to $1,076 million, due to increasing crude oil and natural gas sales prices and higher crude oil sales volumes, partially offset by realized risk management losses compared to gains in 2013, higher royalties and a rise in operating costs. Operating costs increased primarily due to a rise in fuel costs, consistent with the increase in the AECO benchmark price. While higher natural gas prices increased our operating costs, overall the rise in natural gas pricing had a positive impact on Operating Cash Flow as we produced more natural gas than we used.

Increases in upstream Operating Cash Flow were partially offset by lower Operating Cash Flow from our Refining and Marketing segment, which decreased 32 percent to $220 million. The decrease was primarily due to lower market crack spreads, higher heavy crude oil feedstock costs, and increased operating costs partially related to an increase in natural gas prices, offset by an increase in refined product output. The Chicago and Midwest Combined ("Group 3") 3-2-1 market crack spreads decreased by approximately US$10 per barrel or 35 percent.

Cash Flow

Cash Flow increased $318 million to $1,189 million, primarily due to changes discussed above in Operating Cash Flow, a decrease in current income tax and no pre-exploration expense in 2014.



Operating Earnings

Operating Earnings increased $218 million, or 85 percent, to $473 million. The increase was primarily due to higher Cash Flow discussed above and lower exploration expense, partially offset by increased deferred income tax related to operating earnings, and higher non-cash long-term incentive expense.

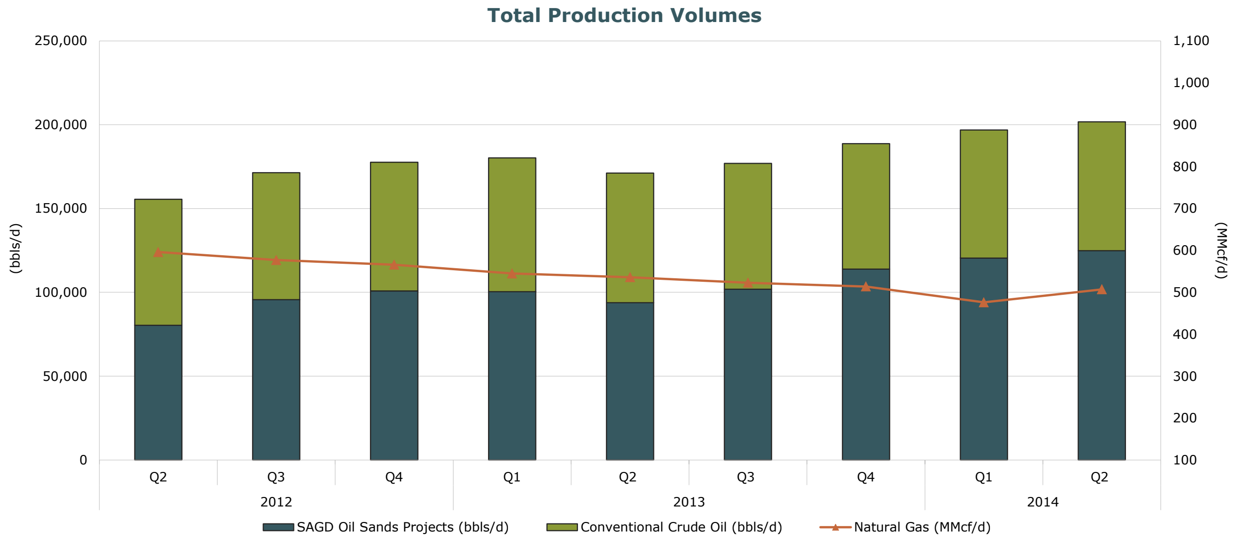
Net Earnings

Net Earnings increased $436 million, to $615 million, primarily due to changes in Operating Earnings discussed above and non-operating unrealized foreign exchange gains on long-term debt and the Partnership Contribution Receivable of $177 million compared with losses of $97 million in 2013.

Capital Investment

Capital investment was $686 million, with most of our spend occurring at our oil sands assets. We continue to focus on the development of our expansion phases at Foster Creek and Christina Lake, and construction at Narrows Lake.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	Three Months Ended June 30, 2014	Percent Change	2013	Six Months Ended June 30, 2014	Percent Change	2013
Oil Sands						
Foster Creek	**56,852**	**3%**	55,338	**55,785**	**-%**	55,665
Christina Lake	**67,975**	**77%**	38,459	**66,863**	**62%**	41,388
	124,827	**33%**	93,797	**122,648**	**26%**	97,053
Conventional						
Pelican Lake	**24,806**	**4%**	23,959	**24,794**	**4%**	23,824
Other Heavy Oil	**15,498**	**(5)%**	16,284	**15,756**	**(4)%**	16,497
Total Heavy Oil	**40,304**	**-%**	40,243	**40,550**	**1%**	40,321
Light & Medium Oil	**35,329**	**(2)%**	36,137	**34,966**	**(6)%**	37,317
NGLs (1)	**1,228**	**29%**	950	**1,121**	**17%**	961
	76,861	**(1)%**	77,330	**76,637**	**(2)%**	78,599
Total Crude Oil Production	**201,688**	**18%**	171,127	**199,285**	**13%**	175,652

(1) NGLs include condensate volumes.

Our crude oil production has increased in 2014, driven by higher production at Christina Lake as a result of phase E reaching nameplate production capacity in the second quarter of 2014. Phase E started producing in July 2013. The ramp up of phase E proceeded similarly to the ramp up of phases C and D, approaching nameplate capacity within six to nine months of first production. In the second quarter of 2014, a planned turnaround was completed at Christina Lake phases A and B. There was minimal impact to production as volumes from phases A and B were processed through the phase C, D and E plant. In the second quarter of 2013, we completed our first major planned turnaround at Christina Lake.

Foster Creek is operating as expected. We are on track with our plan to optimize steam placement and continue to closely monitor conditions in the reservoir to track steam movement between well pads. We are also working to improve how steam moves along individual wells through the use of new operating techniques. Circulation steaming of phase F commenced in the quarter. We expect first production from phase F in the fourth quarter of 2014, with ramp up to design capacity expected to take twelve to eighteen months.

Our Conventional crude oil production decreased slightly in the quarter and for the first half of the year. Increased production from successful horizontal well performance in southern Alberta and higher production at Pelican Lake, was offset by expected natural declines and the divestiture of our Lower Shaunavon and Bakken assets. Lower Shaunavon produced an average of 3,592 barrels per day in the second quarter of 2013 and 4,236 barrels per day in the first six months of 2013. Prior to the sale, crude oil production from these Bakken assets was 396 barrels per day in the first quarter of 2014 (Q2 2013 – 618 barrels per day and for the six months ended June 30, 2013 – 695 barrels per day). Pelican Lake production averaged 24,806 barrels per day, an increase of four percent, resulting from additional infill wells coming on-stream and an increased response from the polymer flood program.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Conventional	**484**	514	**471**	520
Oil Sands	**23**	22	**21**	20
	507	536	**492**	540

In 2014, our natural gas production declined as expected. We continue to focus natural gas capital investment on high rate of return projects and directing the majority of our total capital investment to our crude oil properties.

Operating Netbacks

	Three Months Ended June 30,				Six Months Ended June 30,			
	Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)		Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013
Price [2]	**81.33**	69.61	**4.87**	3.50	**77.29**	61.55	**4.68**	3.38
Royalties	**7.41**	5.03	**0.09**	0.04	**6.59**	4.19	**0.08**	0.05
Transportation and Blending [2]	**3.20**	2.55	**0.11**	0.08	**2.90**	2.69	**0.11**	0.12
Operating Expenses	**16.77**	17.24	**1.23**	1.16	**17.36**	16.18	**1.24**	1.15
Production and Mineral Taxes	**0.60**	0.61	**0.13**	(0.01)	**0.51**	0.58	**0.06**	0.01
Netback Excluding Realized Risk Management	**53.35**	44.18	**3.31**	2.23	**49.93**	37.91	**3.19**	2.05
Realized Risk Management Gain (Loss)	**(2.94)**	0.72	**(0.02)**	0.18	**(2.48)**	1.71	**(0.01)**	0.28
Netback Including Realized Risk Management	**50.41**	44.90	**3.29**	2.41	**47.45**	39.62	**3.18**	2.33

(1) Includes NGLs.
(2) The crude oil price and transportation and blending cost excludes the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate in the second quarter was $32.94 per barrel (2013 – $27.83 per barrel) and in the six months ended June 30, 2014 was $33.73 per barrel (2013 – $29.52 per barrel).

In 2014, our average crude oil netback, excluding realized risk management gains and losses, increased primarily due to higher sales prices, consistent with the strengthening of the West Texas Intermediate ("WTI") and WCS benchmark prices and the weakening of the Canadian dollar.

In 2014, our average natural gas netback, excluding realized risk management gains and losses, increased primarily 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, 2014	Percent Change	2013	Six Months Ended June 30, 2014	Percent Change	2013
Crude Oil Runs (Mbbls/d)	**466**	**6%**	439	**433**	**1%**	428
Heavy Oil	**221**	**(4)%**	230	**208**	**(3)%**	214
Refined Products (Mbbls/d)	**489**	**7%**	457	**458**	**2%**	448
Crude Utilization (percent)	**101**	**5%**	96	**94**	**-%**	94

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

In the quarter, reliable refinery performance resulted in increased crude oil runs and refined product output as compared to 2013. In 2013, our refinery operations were negatively impacted by an unplanned hydrocracker outage. In addition, the timing of planned turnaround and maintenance activities at Borger impacted refined product output, as the 2013 planned turnaround was completed in the second quarter compared to the completion of the 2014 turnaround in the first quarter.

In the first half of the year, our crude oil runs and refined product output increased slightly when compared to the prior year. Reliable refinery performance in the second quarter of 2014 offset the negative impact of the unplanned hydrocracker outage in 2013. Crude utilization remained consistent as a result of the increase in our 2014 refinery capacity.

In 2014, the decrease in heavy oil processed reflected the optimization of our total crude input slate.

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,				
	2014	2013	**Q2 2014**	Q1 2014	Q2 2013
Crude Oil Prices (US$/bbl)					
Brent					
Average	**108.83**	108.00	**109.77**	107.90	103.35
End of Period	**112.36**	102.16	**112.36**	107.76	102.16
WTI					
Average	**100.84**	94.30	**102.99**	98.68	94.22
End of Period	**105.37**	96.56	**105.37**	101.58	96.56
Average Differential Brent-WTI	**7.99**	13.70	**6.78**	9.22	9.13
WCS [2]					
Average	**79.25**	68.74	**82.95**	75.55	75.06
End of Period	**83.18**	82.16	**83.18**	80.71	82.16
Average Differential WTI-WCS	**21.59**	25.56	**20.04**	23.13	19.16
Condensate (C5 @ Edmonton) Average	**103.90**	104.37	**105.15**	102.64	101.50
Average Differential WTI-Condensate (Premium)/Discount	**(3.06)**	(10.07)	**(2.16)**	(3.96)	(7.28)
Average Differential WCS-Condensate (Premium)/Discount	**(24.65)**	(35.63)	**(22.20)**	(27.09)	(26.44)
Average Refined Product Prices (US$/bbl)					
Chicago Regular Unleaded Gasoline ("RUL")	**117.51**	121.15	**121.98**	113.04	124.28
Chicago Ultra-low Sulphur Diesel ("ULSD")	**125.09**	128.22	**124.34**	125.83	126.97
Refining 3-2-1 WTI Average Crack Spreads (US$/bbl)					
Chicago	**19.13**	29.30	**19.72**	18.55	31.06
Group 3	**17.58**	27.59	**17.75**	17.41	27.24
Natural Gas Average Prices					
AECO ($/Mcf)	**4.72**	3.33	**4.67**	4.76	3.59
NYMEX (US$/Mcf)	**4.80**	3.71	**4.67**	4.94	4.09
Basis Differential NYMEX-AECO (US$/Mcf)	**0.50**	0.42	**0.40**	0.60	0.56
Foreign Exchange Rate (US$ per C$1)					
Average	**0.912**	0.984	**0.917**	0.906	0.977

(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 Canadian dollar average WCS benchmark price for the second quarter of 2014 was $90.46 per barrel (2013 – $76.83 per barrel) and for the six months ended June 30, 2014 was $86.90 per barrel (2013 – $69.86 per barrel).

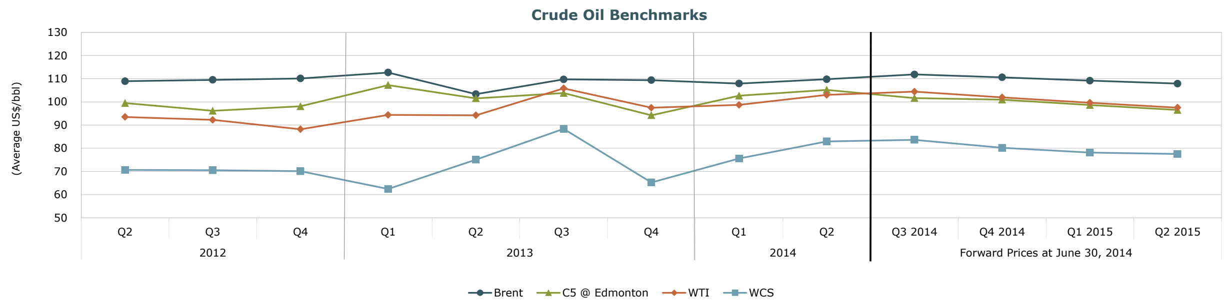
Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. The average price of Brent crude oil increased by US$6.42 per barrel for the three months ended June 30, 2014 compared to 2013. Higher prices were driven by unrest in Iraq resulting in increased risk to Iraqi oil supply and infrastructure. On a year-to-date basis, the average price of Brent crude oil increased by US$0.83 per barrel. Higher prices due to unrest in Iraq were offset by weakness in the first quarter of 2014 as a result of declines in the U.S. economy from adverse weather conditions, economic uncertainty in China and the potential return of Iranian and Libyan production to the global market. In 2013, Brent crude oil prices rose in the first part of the year as a result of global economic optimism. That optimism was later offset by significant North American crude oil supply increases.

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. The average discount between WTI and Brent narrowed in 2014 as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved congestion that developed in the first half of 2013. New pipeline infrastructure allowed inland production greater access to U.S. Gulf Coast refineries and reduced the discount applied to the WTI benchmark price. The 2013 congestion resulted from the rapid growth in U.S. inland supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential widened by US$0.88 per barrel in the three months ended June 30, 2014 compared to last year. This was primarily due to stronger WTI prices resulting from U.S. Gulf Coast refineries having greater access to inland production, as described above. On a year-to-date basis, the differential narrowed by US$3.97 per barrel. This was primarily due to increased Canadian heavy crude oil volumes shipped by rail, providing access to more Canadian and U.S. markets; and higher utilization of existing pipelines and new pipeline capacity, allowing growing Alberta crude oil production improved access to U.S. refineries.

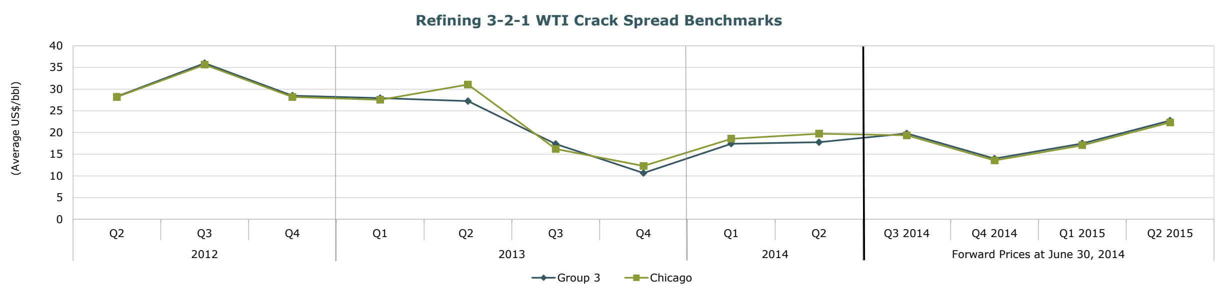
Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Edmonton based condensate prices increased by US$3.65 per barrel in the quarter compared to 2013 due to increased condensate sales to global markets reducing the supply of condensate available in North America, partially offset by additional pipeline capacity to Edmonton. On a year-to-date basis, condensate prices decreased as a result of more pipeline capacity from the U.S. Gulf Coast to Western Canada. The WCS-Condensate differential narrowed in 2014 compared to 2013 primarily due to the increase in the WCS benchmark price as Canadian congestion issues were resolved.



Refining Benchmarks

The Chicago RUL and Chicago ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 Crack Spread. The 3-2-1 WTI 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 valued on a last in, first out accounting basis. Average inland refined product prices declined in 2014 as a result of increased inland refinery utilization, creating additional supply and decreasing the premium over the Brent crude oil benchmark price. Average market crack spreads in the U.S. inland Chicago and Group 3 markets fell in 2014 compared with 2013 primarily due to the strengthening of WTI prices as inland crude oil congestion issues were addressed (as noted above), a reduction in refinery outages in 2014, and a decline in refined product prices.

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 valued on a first in, first out accounting basis.



Other Benchmarks

Average natural gas prices increased in 2014 compared to the prior year due to an abnormally cold winter leading to large draws of natural gas and the subsequent need for larger than normal injections of natural gas into storage.

A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on all of our revenues as the sales prices of our crude oil and natural gas are determined directly in US$ or by reference to US$ benchmarks. In addition, our refining results are in U.S. dollars and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment and results in unrealized foreign exchange losses on our U.S. dollar denominated debt. In the three and six months ended June 30, 2014, the Canadian dollar weakened relative to the U.S. dollar by $0.06 or six percent, and $0.07 or seven percent, respectively. The Canadian dollar weakened due to narrowing of U.S./Canadian interest differentials, as U.S. interest rates rose, while Canadian interest rates increased only slightly as a result of a shift in the Bank of Canada's concern from inflation to deflation risks. The weakening of the Canadian dollar in 2014 as compared with 2013 increased our year-to-date revenues by US$750 million.

FINANCIAL RESULTS

Selected Consolidated Financial Results

For an understanding of the trends and events that impacted our financial results, the following discussion should be read in conjunction with our 2013 annual MD&A and our March 31, 2014 MD&A. The following key performance indicators are discussed in more detail within this section.

($ millions, except per share amounts)	Six Months Ended June 30, 2014	2013	2014 Q2	Q1	2013 Q4	Q3	Q2	Q1	2012 Q4	Q3	Q2
Revenues	**10,434**	8,835	**5,422**	5,012	4,747	5,075	4,516	4,319	3,724	4,340	4,214
Operating Cash Flow (1) (2)	**2,465**	2,339	**1,296**	1,169	976	1,153	1,125	1,214	966	1,314	1,081
Cash Flow (1)	**2,093**	1,842	**1,189**	904	835	932	871	971	697	1,117	925
Per Share – Diluted	**2.76**	2.43	**1.57**	1.19	1.10	1.23	1.15	1.28	0.92	1.47	1.22
Operating Earnings (Loss) (1)	**851**	646	**473**	378	212	313	255	391	(188)	432	284
Per Share – Diluted	**1.12**	0.85	**0.62**	0.50	0.28	0.41	0.34	0.52	(0.25)	0.57	0.37
Net Earnings (Loss)	**862**	350	**615**	247	(58)	370	179	171	(117)	289	397
Per Share – Basic	**1.14**	0.46	**0.81**	0.33	(0.08)	0.49	0.24	0.23	(0.15)	0.38	0.53
Per Share – Diluted	**1.14**	0.46	**0.81**	0.33	(0.08)	0.49	0.24	0.23	(0.15)	0.38	0.52
Capital Investment (3)	**1,515**	1,621	**686**	829	898	743	706	915	978	830	660
Cash Dividends	**403**	367	**201**	202	183	182	183	184	167	166	166
Per Share	**0.5324**	0.484	**0.2662**	0.2662	0.242	0.242	0.242	0.242	0.22	0.22	0.22

(1) Non-GAAP measure defined in this MD&A.
(2) Research activities included in operating expense in prior periods were reclassified to conform to the presentation adopted for the year ended December 31, 2013. This increased Operating Cash Flow in prior periods.
(3) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.

Revenues

In the second quarter, revenues increased $906 million or 20 percent compared with 2013. On a year-to-date basis, revenues increased $1,599 million or 18 percent compared with 2013.

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2013	**4,516**	**8,835**
Increase (Decrease) due to:		
Oil Sands	**456**	**827**
Conventional	**133**	**262**
Refining and Marketing	**405**	**717**
Corporate and Eliminations	**(88)**	**(207)**
Revenues for the Periods Ended June 30, 2014	**5,422**	**10,434**

Upstream revenues, which includes Oil Sands and Conventional, rose in the quarter and year to date by 38 percent and 36 percent, respectively. The increases were primarily due to rising sales prices for crude oil blend and natural gas, and higher blended crude oil sales volumes, partially offset by increased royalties and lower natural gas production.

Revenues for the three and six months ended June 30, 2014 generated by our Refining and Marketing segment increased 13 percent and 12 percent, respectively. Increases due to the weakening of the Canadian dollar and higher refined product output were partially offset by declines in refined product prices. Revenues from third party sales undertaken by the marketing group also rose, primarily due to higher blended crude oil and natural gas sales prices and an increase in purchased crude oil volumes.

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.

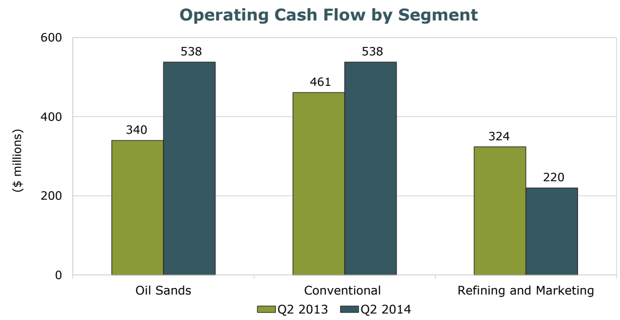
Operating Cash Flow

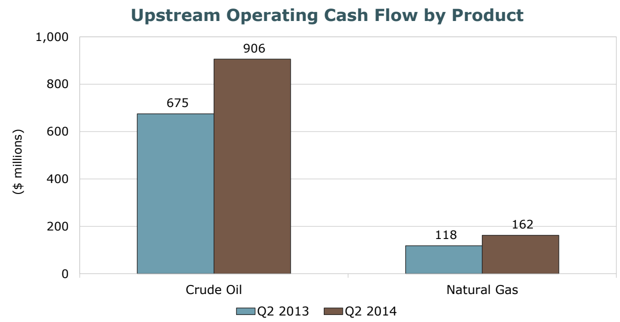
Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, 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 from the calculation of Operating Cash Flow.

Operating Cash Flow

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Revenues	**5,640**	4,646	**10,893**	9,087
(Add) Deduct:				
Purchased Product	**3,098**	2,616	**5,918**	4,893
Transportation and Blending	**655**	460	**1,308**	1,018
Operating Expenses	**519**	456	**1,093**	896
Production and Mineral Taxes	**17**	9	**24**	19
Realized (Gain) Loss on Risk Management Activities	**55**	(20)	**85**	(78)
Operating Cash Flow	**1,296**	1,125	**2,465**	2,339

Three Months Ended June 30, 2014 Compared With June 30, 2013





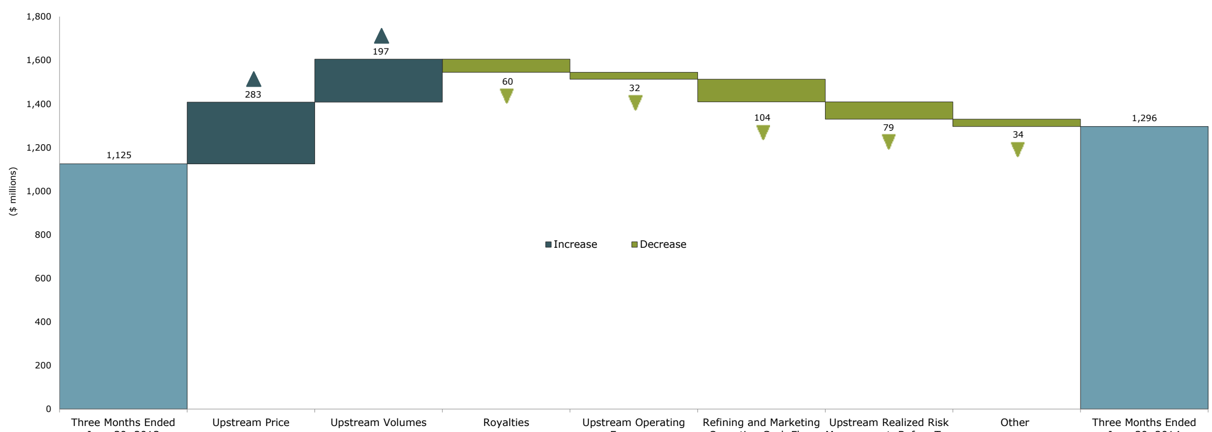
As highlighted in the graph below, our Operating Cash Flow increased 15 percent in the second quarter primarily due to higher upstream revenues resulting from:

- A 17 percent increase in our average crude oil sales price to $81.33 per barrel and a 39 percent increase in our average natural gas sales price to $4.87 per Mcf; and
- An increase in our crude oil sales volumes by 20 percent.

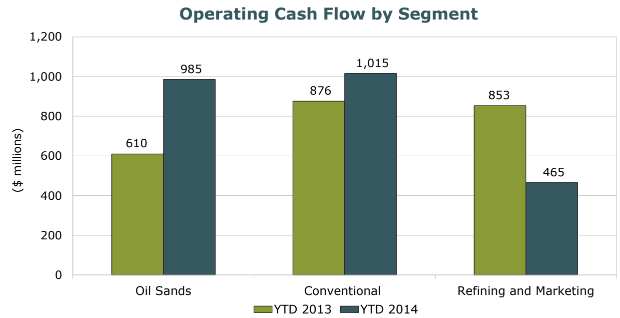
The increases were partially offset by:

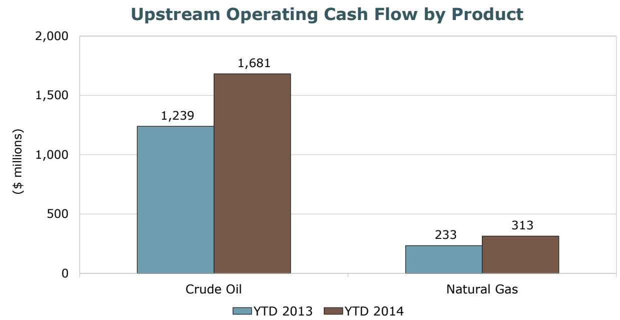
- A decline in Operating Cash Flow from Refining and Marketing of $104 million primarily due to lower market crack spreads and higher heavy crude oil feedstock costs, partially offset by an increase in refined product output;
- Realized risk management losses before tax, excluding Refining and Marketing, of $55 million compared with gains of $24 million in 2013;
- An increase in royalties expense, primarily due to the increase in crude oil sales prices; and
- Higher crude oil operating expenses of $37 million, primarily due to higher fuel costs. On a per barrel basis, crude oil operating costs decreased by $0.47 to $16.77 per barrel, due to the substantial increase in production at Christina Lake, partially offset by an increase of $0.94 per barrel in fuel costs, primarily related to an increase in natural gas prices.

Operating Cash Flow Variance



Six Months Ended June 30, 2014 Compared With June 30, 2013





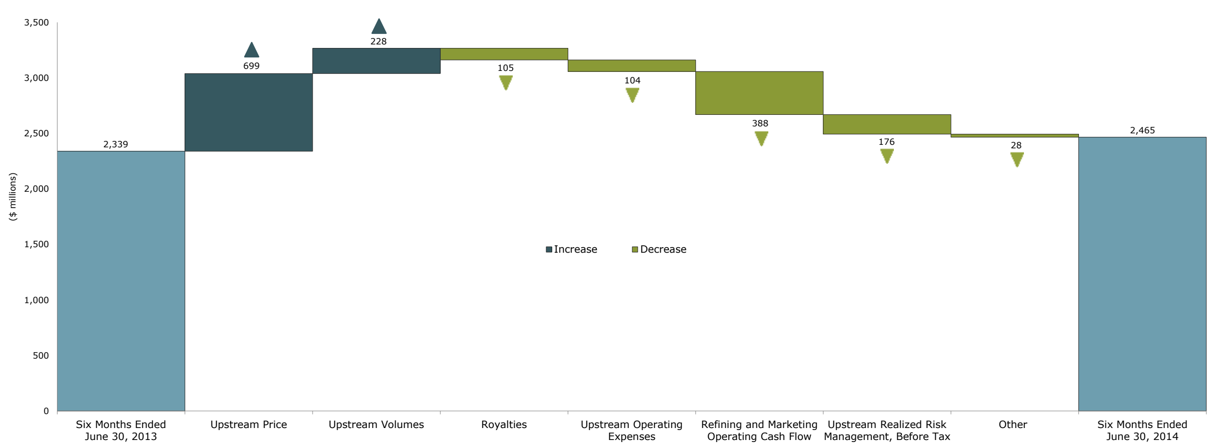
As highlighted in the graph below, our Operating Cash Flow increased five percent in the first six months of 2014 primarily due to higher upstream revenues resulting from:

- A 26 percent increase in our average crude oil sales price to $77.29 per barrel and a 38 percent increase in our average natural gas sales price to $4.68 per Mcf; and
- An increase in our crude oil sales volumes by 13 percent.

The increases were partially offset by:

- A decline in Operating Cash Flow from Refining and Marketing of $388 million primarily due to lower market crack spreads and higher heavy crude oil feedstock costs, partially offset by higher refined product output;
- Realized risk management losses before tax, excluding Refining and Marketing, of $90 million compared with gains of $86 million in 2013;
- Higher royalties expense, primarily due to the increase in crude oil sales prices; and
- An increase in crude oil operating expenses of $105 million, primarily due to a rise in fuel costs consistent with the increase in the AECO natural gas price. The impact of rising natural gas prices on our operating expenses was offset by the increase in natural gas revenues, as we produced more natural gas than we used. On a per barrel basis, crude oil operating costs increased by $1.18 to $17.36 per barrel, with an increase of $1.14 per barrel in fuel costs, primarily related to an increase in natural gas prices.

Operating Cash Flow Variance



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.

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Cash From Operating Activities	**1,109**	828	**1,566**	1,723
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(27)**	(31)	**(69)**	(65)
Net Change in Non-Cash Working Capital	**(53)**	(12)	**(458)**	(54)
Cash Flow	**1,189**	871	**2,093**	1,842

In the three and six months ended June 30, 2014, Cash Flow increased $318 million and $251 million, respectively, primarily due to:

- Higher Operating Cash Flow, as discussed above;
- A decrease in current income tax, primarily due to a favourable adjustment related to prior years, a decrease in U.S. cash flow, partially offset by an increase in Canadian cash flow; and
- A pre-exploration expense of $63 million recorded in the second quarter of 2013.

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 Earnings Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings.

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Earnings, Before Income Tax	**824**	280	**1,182**	574
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (1)	**11**	(26)	**(15)**	204
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**(177)**	97	**19**	144
(Gain) Loss on Divestiture of Assets	**(20)**	-	**(20)**	-
Operating Earnings, Before Income Tax	**638**	351	**1,166**	922
Income Tax Expense	**165**	96	**315**	276
Operating Earnings	**473**	255	**851**	646

(1) *The unrealized risk management (gains) losses includes the reversal of unrealized (gains) losses recognized in prior periods.*

(2) *Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable and foreign exchange (gains) losses on settlement of intercompany transactions.*

Operating Earnings increased $218 million in the second quarter and $205 million on a year-to-date basis, primarily due to:

- Higher Cash Flow discussed above; and
- A decrease in exploration expense related to previously capitalized E&E costs.

Increases in Operating Earnings were partially offset by:

- An increase in deferred income tax primarily as a result of higher Canadian income; and
- Higher non-cash long-term incentive expense as compared to 2013.

Net Earnings

($ millions)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2013	**179**	**350**
Increase (Decrease) due to:		
Operating Cash Flow [(1)]	**171**	**126**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(37)**	**219**
Unrealized Foreign Exchange Gain (Loss)	**265**	**172**
Gain (Loss) on Divestiture of Assets	**20**	**20**
Expenses [(2)]	**23**	**(32)**
Depreciation, Depletion and Amortization	**(6)**	**(5)**
Exploration Expense	**108**	**108**
Income Tax Expense	**(108)**	**(96)**
Net Earnings for the Periods Ended June 30, 2014	**615**	**862**

(1) Non-GAAP measure defined in this MD&A.
(2) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations operating expenses.

Our Net Earnings for the three and six months ended June 30, 2014 increased by $436 million and $512 million, respectively, primarily due to the increase in Cash Flow and Operating Earnings as discussed above:

- Non-operating unrealized foreign exchange gains of $177 million in the quarter and losses of $19 million on a year-to-date basis (2013 – unrealized foreign exchange losses of $97 million and $144 million, respectively); and
- Unrealized risk management losses of $11 million in the quarter and gains of $15 million on a year-to-date basis (2013 – unrealized gains of $26 million and unrealized losses of $204 million, respectively).

Net Capital Investment

($ millions)	Three Months Ended June 30, **2014**	2013	Six Months Ended June 30, **2014**	2013
Oil Sands	**471**	420	**998**	957
Conventional	**153**	245	**423**	583
Refining and Marketing	**46**	26	**69**	51
Corporate	**16**	15	**25**	30
Capital Investment	**686**	706	**1,515**	1,621
Acquisitions	**16**	1	**17**	4
Divestitures	**(39)**	-	**(41)**	(1)
Net Capital Investment [(1)]	**663**	707	**1,491**	1,624

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

Oil Sands capital investment in 2014 focused primarily on the development of the expansion phases at Foster Creek and Christina Lake, and the construction of phase A at Narrows Lake. Capital investment includes the drilling of 284 gross stratigraphic test wells.

In 2014, Conventional capital investment focused primarily on tight oil development, facilities work and on the expansion of the polymer flood at Pelican Lake. Spending on natural gas activities continues to be strategically focused on a small number of high return opportunities.

Our capital investment in the Refining and Marketing segment focused on capital maintenance and projects improving refinery reliability and safety in 2014.

Capital also includes spending on technology development, which plays an integral role in our business. Having an integrated innovation and technology development strategy is vital to our ability to minimize our environmental footprint and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to potentially reduce costs, 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 includes spending on corporate assets, such as computer equipment, leasehold improvements and office furniture.

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 uses of cash flow in the following manner:

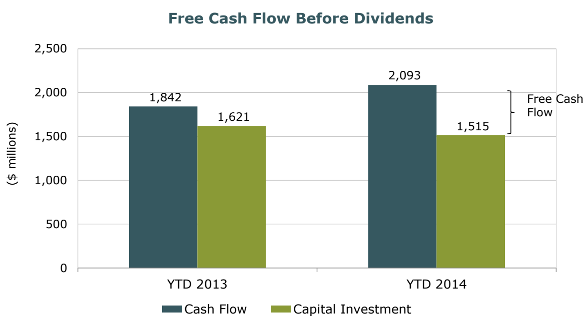
- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third,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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2014**	2013	**2014**	2013
Cash Flow [1]	**1,189**	871	**2,093**	1,842
Capital Investment (Committed and Growth)	**686**	706	**1,515**	1,621
Free Cash Flow [2]	**503**	165	**578**	221
Dividends Paid	**201**	183	**403**	367
	302	(18)	**175**	(146)

(1) Non-GAAP measure defined in this MD&A.
(2) Free Cash Flow is a non-GAAP measure defined as Cash Flow less capital investment.

While 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 prudent use of balance sheet capacity and management of our asset portfolio.



Approximately two-thirds of our planned 2014 capital investment is for committed capital, which is used to progress approved expansions at Foster Creek and Christina Lake, construction of phase A at Narrows Lake and support existing business operations. The remaining one-third is discretionary capital for activities that include further developing our tight oil opportunities, advancing future oil sands expansions through the regulatory process and investment in technology development. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

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 projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. 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 heavy oil assets at Pelican Lake. This segment also includes 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, an unrelated U.S. public company. 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.

■ Cenovus's major operations   This graphic is for illustration purposes only, Land as at December 31, 2013.

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, research costs 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.

The operating and reportable segments shown above reflect the change in Cenovus's operating structure adopted for the year ended December 31, 2013; as such, prior periods have been restated. In addition, research activities previously included in operating expense have been reclassified to conform to the presentation adopted for the year ended December 31, 2013.

Revenues by Reportable Segment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2014**	2013	**2014**	2013
Oil Sands	**1,301**	845	**2,510**	1,683
Conventional	**856**	723	**1,642**	1,380
Refining and Marketing	**3,483**	3,078	**6,741**	6,024
Corporate and Eliminations	**(218)**	(130)	**(459)**	(252)
	5,422	4,516	**10,434**	8,835

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of assessment, including our 100 percent-owned projects at Telephone Lake and Grand Rapids. 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 of 2014 compared with 2013 include:

- Commencing circulation steaming at Foster Creek phase F;
- Successfully completing a planned turnaround at Christina Lake phases A and B, with minimal impact to production;
- Christina Lake production increasing 77 percent, to an average of 67,975 barrels per day, with phase E reaching nameplate production capacity;
- Foster Creek production averaging 56,852 barrels per day, in line with our expectations; and
- Receiving anticipated regulatory approval for expansion of the Foster Creek development area.

Oil Sands – Crude Oil

Financial Results

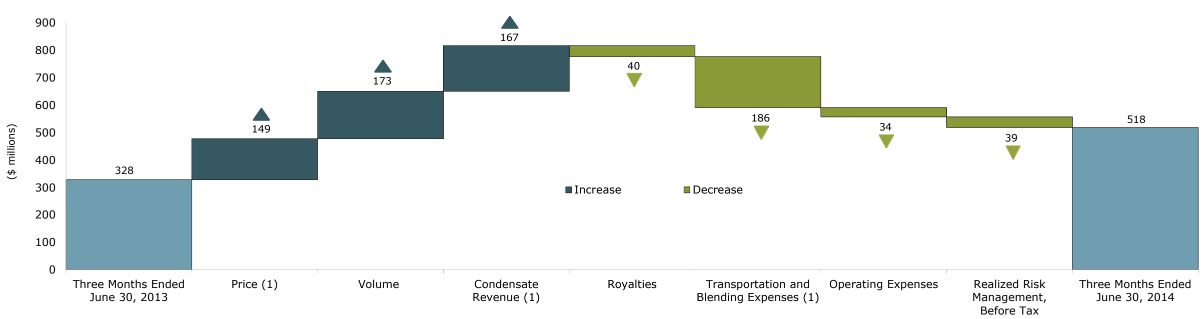
($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Gross Sales	**1,345**	856	**2,575**	1,697
Less: Royalties	**67**	27	**118**	41
Revenues	**1,278**	829	**2,457**	1,656
Expenses				
Transportation and Blending	**559**	373	**1,118**	838
Operating	**166**	132	**336**	255
(Gain) Loss on Risk Management	**35**	(4)	**57**	(27)
Operating Cash Flow (1)	**518**	328	**946**	590
Capital Investment	**470**	419	**995**	955
Operating Cash Flow Net of Related Capital Investment	**48**	(91)	**(49)**	(365)

(1) *Non-GAAP measure defined in this MD&A.*

Capital investment in excess of Operating Cash Flow is funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

Three Months Ended June 30, 2014 Compared With June 30, 2013

Operating Cash Flow Variance



(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.*

Revenues

Pricing

In the second quarter, our average crude oil sales price was $75.65 per barrel, 22 percent higher than in 2013. This is consistent with the increase in the WCS benchmark price, the strengthening of the Christina Dilbit Blend ("CDB") price and the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 26 percent, to a discount of US$4.33 per barrel (2013 – US$5.82 per barrel), primarily related to improved pipeline access to the U.S. Gulf Coast and the associated access to refineries that can process heavier crude oil. In the second quarter, 54,982 barrels per day of Christina Lake production was sold as CDB (2013 – 32,894 barrels per day), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	Three Months Ended June 30, 2014	Percent Change	2013
Foster Creek	**56,852**	**3%**	55,338
Christina Lake	**67,975**	**77%**	38,459
	124,827	**33%**	93,797

In line with our expectations, Foster Creek production averaged 56,852 barrels per day in the second quarter of 2014. We continue to optimize steam placement and are pursuing new technologies to improve the conformance of steam along wellbores. In addition, we continue to use our Wedge Well™ technology to capture production from areas between steam chambers. In the near-term, we expect to continue to see a higher steam to oil ratio ("SOR") and production levels between 100,000 and 110,000 gross barrels per day. As we continue to learn more about operating a SAGD project with common steam chambers and build out the remaining phases, we will look to further optimize both the SOR and plant upgrades for the entire facility.

Christina Lake production increased primarily as a result of phase E reaching nameplate production capacity. In addition, there was a reduction in downtime due to the smaller scope of the 2014 turnaround as compared to an 11 day full production outage in 2013. The 2014 planned turnaround had minimal impact on production as volumes from phases A and B were processed through the phase C, D and E plant. In the second quarter of 2013, the turnaround reduced production by approximately 7,600 barrels per day.

Condensate

The bitumen produced by Cenovus must be blended with condensate to reduce its viscosity in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate. As the WCS benchmark price narrows in relation to the Condensate benchmark we recover a larger proportion of the cost to blend our product. Consistent with the narrowing of the WCS-Condensate benchmark, the proportion of the cost of condensate recovered increased in the second quarter of 2014 compared to 2013.

Royalties

Royalty calculations for our Oil Sands projects 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. Royalty calculations differ between properties.

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, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project. Gross revenues are a function of sales volumes and realized prices.

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Net profits are a function of sales volumes, realized prices and allowed operating and capital costs.

Effective Royalty Rates

(percent)	Three Months Ended June 30, 2014	2013
Foster Creek	**9.3**	5.7
Christina Lake	**7.7**	5.6

Royalties increased $40 million in the second quarter of 2014, primarily due to higher realized prices at both Foster Creek and Christina Lake, an increase in sales volumes at Christina Lake, and a rise in the Canadian dollar equivalent WTI benchmark price. At Foster Creek this resulted in a royalty calculation based on net profits as compared to a calculation based on gross revenues in 2013.

Expenses

Transportation and Blending

Transportation and blending costs rose $186 million or 50 percent. Blending costs rose $167 million due to higher production and an increase in the cost of condensate, consistent with the change in benchmark prices. Transportation charges were $19 million higher primarily due to production increases.

Operating

Our operating costs for the second quarter were primarily for workforce, fuel, and workover activities. In total, operating costs increased $34 million and decreased on a per barrel basis by $1.07 per barrel, consistent with the increase in production.

Per-unit Operating Costs

	Three Months Ended June 30,		
($/bbl)	**2014**	**Percent Change**	2013
Foster Creek			
Fuel	**4.60**	**63%**	2.83
Non-fuel	**14.78**	**11%**	13.36
Total	**19.38**	**20%**	16.19
Christina Lake			
Fuel	**3.86**	**15%**	3.37
Non-fuel	**8.22**	**(39)%**	13.46
Total	**12.08**	**(28)%**	16.83

In the second quarter, Foster Creek operating costs rose $3.19 per barrel, primarily due to:

- Fuel costs increasing by $1.77 per barrel related to the rise in natural gas prices, consistent with the rising benchmark AECO price, and higher consumption;
- Higher workforce costs primarily related to the rise in long-term incentive costs, consistent with the increase in our share price; and
- Increased workover activities related to well servicing.

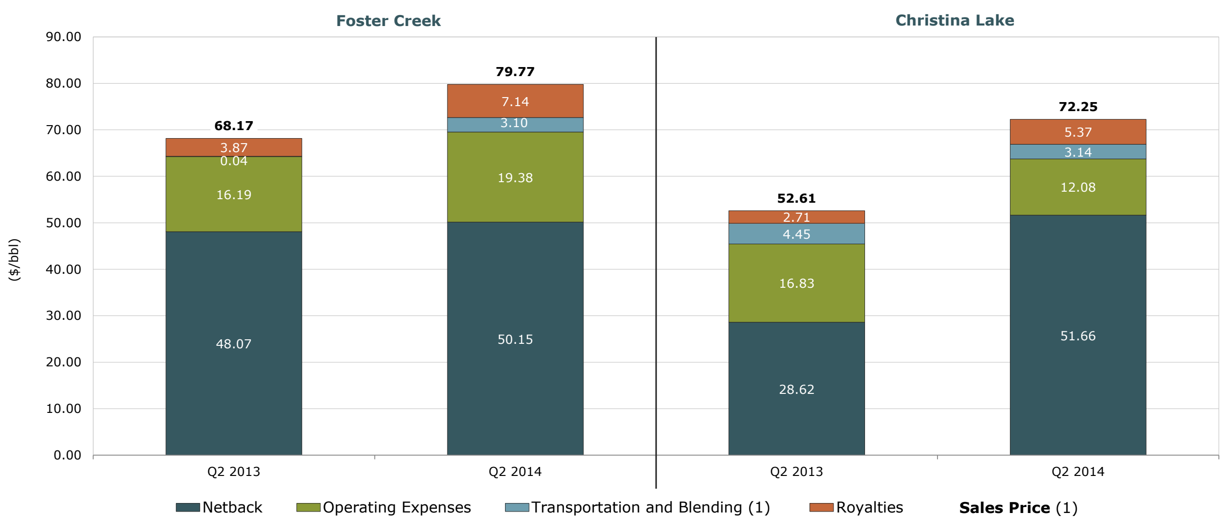
Increases were partially offset by decreases in the cost of electricity, primarily related to a decline in the price of electricity.

Christina Lake operating costs decreased $4.75 per barrel, primarily due to an increase in production.

Decreases were partially offset by:

- Fuel costs increasing by $0.49 per barrel primarily due to the rise in natural gas prices, consistent with the rising benchmark AECO price; and
- An increase in workover activities related to well servicing.

Operating Netbacks



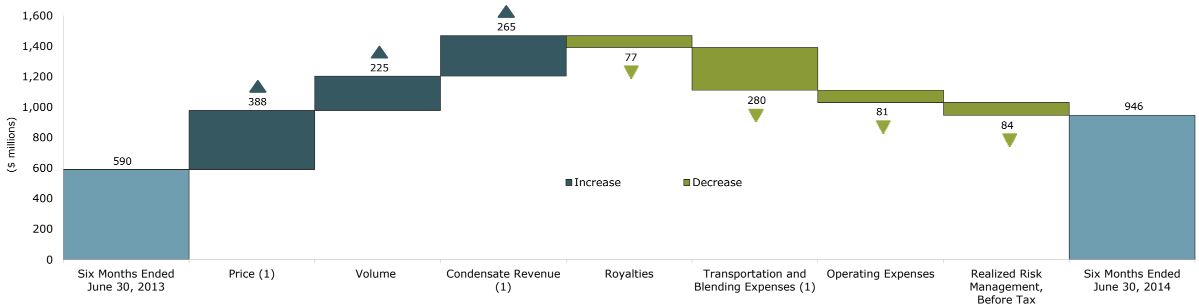
(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate in the second quarter was $47.28 per barrel (2013 – $42.60 per barrel) for Foster Creek and $49.30 per barrel (2013 – $47.13 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

Risk Management

Risk management activities resulted in realized losses of $35 million in the second quarter of 2014 (2013 – realized gains of $4 million), consistent with average benchmark prices exceeding our contract prices.

Six Months Ended June 30, 2014 Compared With June 30, 2013

Operating Cash Flow Variance



(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.

Revenues

Pricing

For the six months ended June 30, 2014, our average crude oil sales price was $70.48 per barrel, a 34 percent increase from 2013. This is consistent with the increase in the WCS benchmark price, the strengthening of the CDB price and the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 31 percent, to a discount of US$4.61 per barrel (2013 – US$6.67 per barrel), primarily related to the reasons discussed previously for the current quarter. Year to date, 54,414 barrels per day of Christina Lake production was sold as CDB (2013 – 35,247 barrels per day), with the remainder sold into the WCS stream.

Production Volumes

	Six Months Ended June 30,		
(barrels per day)	**2014**	**Percent Change**	2013
Foster Creek	**55,785**	**-%**	55,665
Christina Lake	**66,863**	**62%**	41,388
	122,648	**26%**	97,053

On a year-to-date basis, production remained flat at Foster Creek, in line with expectations as previously discussed. The substantial increase in production at Christina Lake resulted from phase E reaching nameplate production capacity in the second quarter of 2014. We completed a partial planned turnaround in 2014 which had minimal impact on production. In 2013, a full planned turnaround was performed which reduced production by approximately 3,800 barrels per day for the six months.

Condensate

As the WCS benchmark price narrows in relation to the Condensate benchmark we recover a larger proportion of the cost to blend our product. The proportion of the cost of condensate recovered increased on a year-to-date basis compared to 2013, consistent with the narrowing of the WCS-Condensate differential.

Royalties

	Six Months Ended June 30,	
(percent)	**2014**	2013
Foster Creek	**8.7**	4.5
Christina Lake	**7.4**	5.6

Royalties increased $77 million in 2014 primarily related to higher realized prices at both Foster Creek and Christina Lake, an increase in sales volumes at Christina Lake, and a rise in the Canadian dollar equivalent WTI benchmark price. At Foster Creek this resulted in a royalty calculation based on net profits as compared to a calculation based on gross revenues in 2013.

Expenses

Transportation and Blending

Transportation and blending costs rose $280 million or 33 percent year to date. Blending costs rose $265 million due to higher production and an increase in the cost of condensate. Transportation charges were $15 million higher primarily due to production increases.

Operating

In the first half of 2014, operating costs were primarily for fuel, workforce and workover activities. In total, operating costs increased $81 million or $0.77 per barrel.

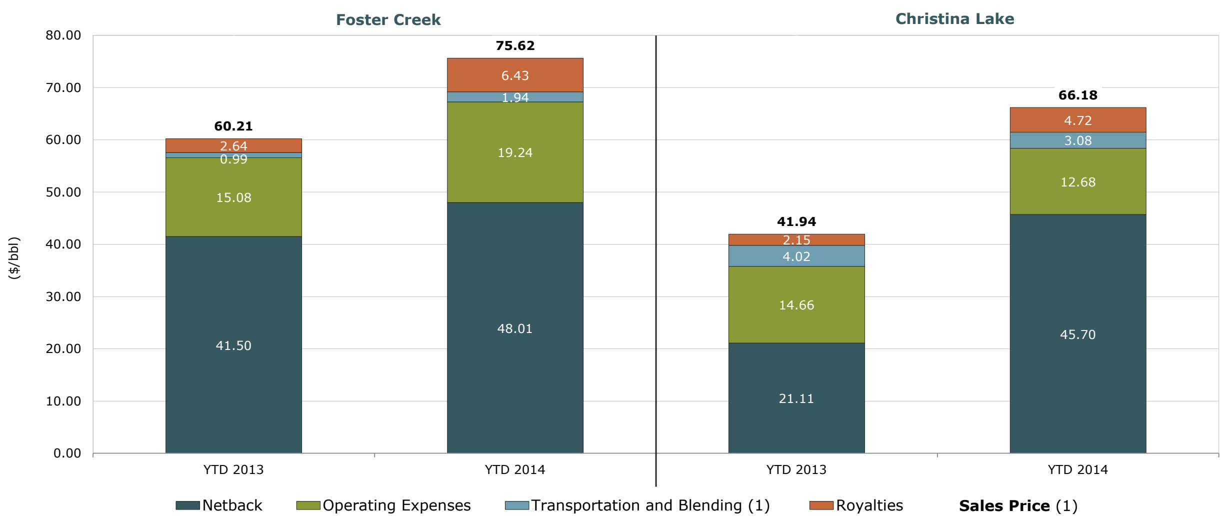
Per-unit Operating Costs

($/bbl)	Six Months Ended June 30, 2014	Percent Change	2013
Foster Creek			
Fuel	**5.03**	**75%**	2.87
Non-fuel	**14.21**	**16%**	12.21
Total	**19.24**	**28%**	15.08
Christina Lake			
Fuel	**4.33**	**22%**	3.55
Non-fuel	**8.35**	**(25)%**	11.11
Total	**12.68**	**(14)%**	14.66

At Foster Creek operating costs rose $4.16 per barrel primarily due to higher fuel prices and consumption, workforce and workover activities, as discussed previously.

Christina Lake operating costs decreased $1.98 per barrel primarily due to our production growth. Decreases were offset by higher fuel prices and an increase in workover activities.

Operating Netbacks



(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for the six months ended June 30, 2014 was $47.81 per barrel (2013 – $44.34 per barrel) for Foster Creek and $51.02 per barrel (2013 – $49.54 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

Risk Management

Risk management activities resulted in realized losses of $57 million in the first six months of 2014 (2013 – realized gains of $27 million), consistent with average benchmark prices exceeding our contract prices.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent-owned natural gas operation in Athabasca. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production, net of internal usage, for the three and six months ended June 30, 2014 remained consistent at 23 MMcf per day and 21 MMcf per day, respectively (2013 – 22 MMcf per day and 20 MMcf per day, respectively). Operating Cash Flow was $15 million in the second quarter of 2014 (2013 – $6 million) and $38 million on a year-to-date basis (2013 – $10 million). The increases were due to higher realized natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Foster Creek	**209**	189	**430**	399
Christina Lake	**183**	162	**365**	337
	392	351	**795**	736
Narrows Lake	**45**	25	**92**	50
Telephone Lake	**19**	17	**71**	70
Grand Rapids	**5**	8	**16**	26
Other (1)	**10**	19	**24**	75
Capital Investment (2)	**471**	420	**998**	957

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

Existing Projects

Capital investment at Foster Creek in 2014 focused on expansion phases F, G and H, drilling of sustaining wells, and operational improvement projects. Capital investment increased in the second quarter and on a year-to-date basis due to phase F well pad construction, drilling using Wedge Well™ technology, and an increase in stratigraphic test wells drilled.

In 2014, Christina Lake capital investment focused on expansion phase F, phase E well pad and facility construction, and Wedge Well™ technology and sustaining well programs. Capital investment increased in the second quarter and on a year-to-date basis due to higher spending on our Wedge Well™ technology and sustaining well programs, and phase F plant construction, partially offset by lower spending on phase E plant construction.

Capital investment at Narrows Lake increased in the three and six months ended June 30, 2014, as spending continued on phase A engineering, procurement, and plant construction, which started in the third quarter of 2013.

Emerging Projects

In 2014, Telephone Lake capital investment was primarily focused on front end engineering and costs related to the dewatering pilot project and the drilling of stratigraphic test wells. We are currently executing a summer stratigraphic well program using our SkyStrat™ drilling rig. Capital spending in 2014 remained relatively consistent to 2013.

Capital investment at Grand Rapids in 2014 was primarily focused on costs related to the pilot project and the drilling of stratigraphic test wells. In the first quarter of 2014, we received regulatory approval for a 180,000 barrel per day commercial SAGD operation. Capital investment declined in the three and six months ended June 30, 2014. Reductions in spending on the pilot project were partially offset by the initiation of the dismantling of the Joslyn central plant facility to be relocated and used for Phase A.

Drilling Activity

Consistent with our strategy to further delineate our resources, we completed another stratigraphic test well program over the winter drilling season.

Six Months Ended June 30,	Gross Stratigraphic Test Wells (1) 2014	2013	Gross Production Wells (2) (3) 2014	2013
Foster Creek	**147**	111	**38**	25
Christina Lake	**52**	69	**35**	11
	199	180	**73**	36
Narrows Lake	**22**	26	**-**	-
Telephone Lake	**33**	28	**-**	-
Grand Rapids	**9**	1	**-**	-
Other	**21**	80	**-**	-
	284	315	**73**	36

(1) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In the six months ended June 30, 2014, we drilled two wells (2013 – eight wells).
(2) SAGD well pairs are counted as a single producing well.
(3) Includes wells drilled using our Wedge Well™ technology.
(4) In addition to the drilling activity noted above, we drilled one gross service well in the six months ended June 30, 2014 (2013 – 16 gross service wells).

Future Capital Investment

Foster Creek is currently producing from phases A through E. Expansion work is underway at phases F, G and H. Foster Creek capital investment for 2014 is forecast to be between $680 million and $760 million and is primarily focused on expansion phases, sustaining wells and operational improvement projects. Expansion work at phases F, G and H is proceeding as planned. We expect phases F, G and H to each add initial design capacity of 30,000 barrels per day. We will continue to focus on optimizing production performance and monitoring our long-term reservoir management plan. Circulation steaming commenced at phase F in the second quarter of 2014. Production from phase F is expected to start in the fourth quarter of 2014 with ramp-up to design capacity expected to take twelve to eighteen months. Production start-up from phases G and H is anticipated in 2015 and 2016, respectively. We submitted a joint application and environmental impact assessment ("EIA") to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. In the second quarter of 2014, we received anticipated regulatory approval for a Foster Creek development area expansion.

Christina Lake is producing from phases A through E. Expansion work is currently underway for phase F, including cogeneration, and phase G, with added production capacity expected in 2016 and 2017, respectively. Christina Lake capital investment in 2014 is forecast to be between $750 million and $820 million and is primarily focused on expansion phases F and G, the phase C, D and E optimization program, and drilling and facilities work for drilling using our Wedge Well™ technology and sustaining wells. Phase E development spending for well pad and facility construction is expected to continue to the end of 2014. Expansion work on phases F, including cogeneration, and G is continuing as planned and we expect to add gross production capacity of 50,000 barrels per day from each phase. We submitted a joint application and EIA to regulators in the first quarter of 2013 for the phase H expansion, a 50,000 barrel per day phase for which we expect to receive 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. Construction of the phase A plant commenced in August 2013. Capital investment at Narrows Lake is forecast to be between $210 million and $230 million in 2014 and is primarily focused on plant construction, procurement and offsite fabrication for phase A and infrastructure for a construction camp.

Two of our emerging projects are Telephone Lake and Grand Rapids. At our Telephone Lake project located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012 and we completed the pilot in October 2013. At our Grand Rapids project located within the Greater Pelican region, we received regulatory approval in March 2014 for a 180,000 barrel per day commercial SAGD operation. We plan to develop Grand Rapids through a series of expansion phases. Phase A is expected to produce between 8,000 and 10,000 barrels per day, with first steam planned in 2017. The project will benefit from the purchase of an existing central plant facility that will be relocated to the Grand Rapids project site. We continue to operate a SAGD pilot project to gather additional information on the reservoir.

Capital investment of approximately $140 million to $160 million in 2014 is expected for our emerging oil sands projects and is primarily focused on drilling stratigraphic test wells, front end engineering at Telephone Lake and Grand Rapids, as well as costs related to the pilot project at Grand Rapids. At Telephone Lake we are advancing the regulatory application for the project and anticipate receiving approval in the second half of 2014. The first two phases of the project are anticipated to have a production capacity of 90,000 barrels per day.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves as estimated by our independent qualified reserves evaluators. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by total proved reserves.

The following calculation illustrates how the implied depletion rate for our upstream assets could be determined using the reported consolidated data:

($ millions, unless otherwise indicated)	As at December 31, 2013
Upstream Property, Plant and Equipment	13,692
Estimated Future Development Capital	17,795
Total Estimated Upstream Cost Base	31,487
Total Proved Reserves (MBOE)	2,284
Implied Depletion Rate ($/BOE)	13.79

While this illustrates the calculation of the implied depletion rate, our depletion rates are slightly higher and result in a total average rate ranging between $15.50 to $16.00 per BOE. Amounts related to assets under construction, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the Consolidated Financial Statements.

In the three and six months ended June 30, 2014, Oil Sands DD&A increased $53 million and $91 million, respectively. The increases were due to higher sales volumes, and higher DD&A rates for both of our properties from additional expenditures and a rise in future development costs associated with total proved reserves.

CONVENTIONAL

Our Conventional operations include predictable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn, the heavy oil assets at Pelican Lake and developing tight oil assets in Alberta. Pelican Lake produces conventional heavy oil using polymer flood technology. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced.

Furthermore, we own the mineral rights on approximately 70 percent or 4.5 million net acres of our conventional lands (fee lands), of which 2.5 million acres are developed. Our ownership of fee lands benefits our netback. Fee lands where we have maintained a working interest are subject to mineral tax, which is generally lower than the royalties paid to the government or other mineral interest owners. Of the 4.5 million net acres of fee land, we lease over 2.0 million acres to third parties, which may result in royalty income. In the first half of 2014, we had approximately 7,800 barrels of oil equivalent per day of royalty interest production from fee lands. Production from fee lands comprises approximately 50 percent of our total conventional production.

Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment.

Significant factors that impacted our Conventional segment in the second quarter of 2014 compared with 2013 include:

- Crude oil production averaging 76,861 barrels per day, decreasing one percent. Increased production from successful horizontal well performance in southern Alberta and higher production at Pelican Lake, was offset by expected natural declines and the sale of our Lower Shaunavon and Bakken assets; and
- Generating Operating Cash Flow net of related capital investment of $385 million, an increase of $169 million.

In March 2014, we entered into a purchase and sale agreement with an unrelated third party, to sell certain of our Bakken assets in southeastern Saskatchewan. The sale was completed in April 2014 for proceeds of $36 million before closing adjustments. A gain on disposition of $16 million was recorded on the sale. Prior to the sale, crude oil production from these Bakken assets was 396 barrels per day in the first quarter of 2014 (Q2 2013 – 618 barrels per day and YTD 2013 – 695 barrels per day, respectively).

In July 2013, we sold our Lower Shaunavon asset for proceeds of approximately $240 million before closing adjustments. Lower Shaunavon produced an average of 3,592 barrels per day in the second quarter of 2013 and 4,236 barrels per day in the first six months of 2013.

Conventional – Crude Oil

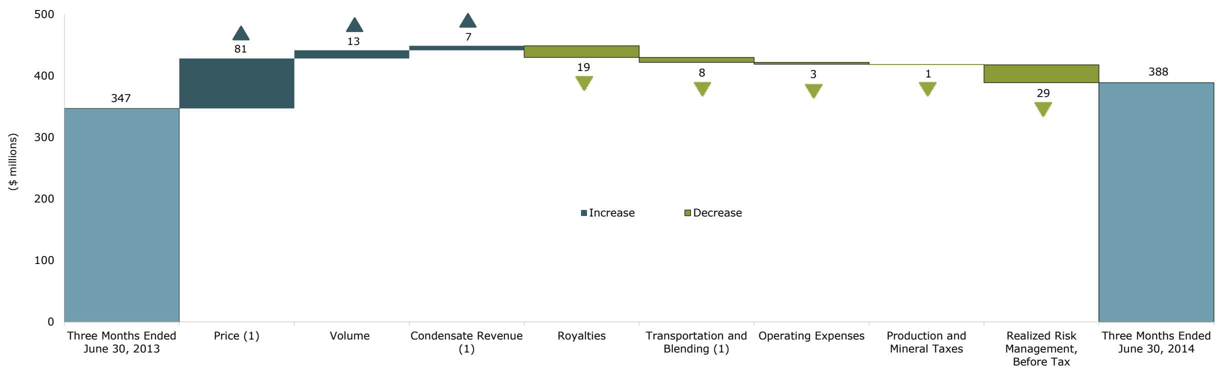
Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2014**	2013	**2014**	2013
Gross Sales	**708**	607	**1,359**	1,150
Less: Royalties	**67**	48	**116**	90
Revenues	**641**	559	**1,243**	1,060
Expenses				
Transportation and Blending	**91**	83	**180**	169
Operating	**133**	130	**278**	254
Production and Mineral Taxes	**10**	9	**18**	18
(Gain) Loss on Risk Management	**19**	(10)	**32**	(30)
Operating Cash Flow [(1)]	**388**	347	**735**	649
Capital Investment	**149**	241	**412**	571
Operating Cash Flow Net of Related Capital Investment	**239**	106	**323**	78

(1) Non-GAAP measure defined in this MD&A.

Three Months Ended June 30, 2014 Compared With June 30, 2013

Operating Cash Flow Variance



(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.

Revenues

Pricing

Our average crude oil sales price in the quarter increased 15 percent to $89.98 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

	Three Months Ended June 30,		
(barrels per day)	**2014**	**Percent Change**	2013
Pelican Lake	**24,806**	**4%**	23,959
Other Heavy Oil	**15,498**	**(5)%**	16,284
Total Heavy Oil	**40,304**	**-%**	40,243
Light and Medium Oil	**35,329**	**(2)%**	36,137
NGLs	**1,228**	**29%**	950
	76,861	**(1)%**	77,330

Increased production from successful horizontal well performance in southern Alberta and higher production at Pelican Lake, was offset by expected natural declines and the divestiture of our Lower Shaunavon and Bakken assets. Pelican Lake production increased as a result of additional infill wells coming on-stream and an increased response from the polymer flood program.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate. In the quarter, the value of condensate increased $7 million compared to 2013. The proportion of the cost of condensate recovered increased, consistent with the narrowing of the WCS-Condensate differential.

Royalties

Royalties increased $19 million primarily due to higher realized prices, an increase in sales volumes at Pelican Lake, and a rise in the Canadian dollar equivalent WTI benchmark price.

Royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses 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 sales volumes, realized prices and allowed operating and capital costs. In 2014 and 2013, the Pelican Lake royalty calculation was based on gross revenues. Our other conventional crude oil producing assets are located primarily on crown or fee lands. Production from fee lands results in mineral tax recorded within production and mineral taxes.

In the second quarter of 2014, the effective crude oil royalty rate for all of our Conventional properties was 10.8 percent (2013 – 9.3 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $8 million in the second quarter of 2014, primarily due to higher condensate costs as discussed in the Revenues section. Transportation costs remained relatively consistent compared to 2013.

Operating

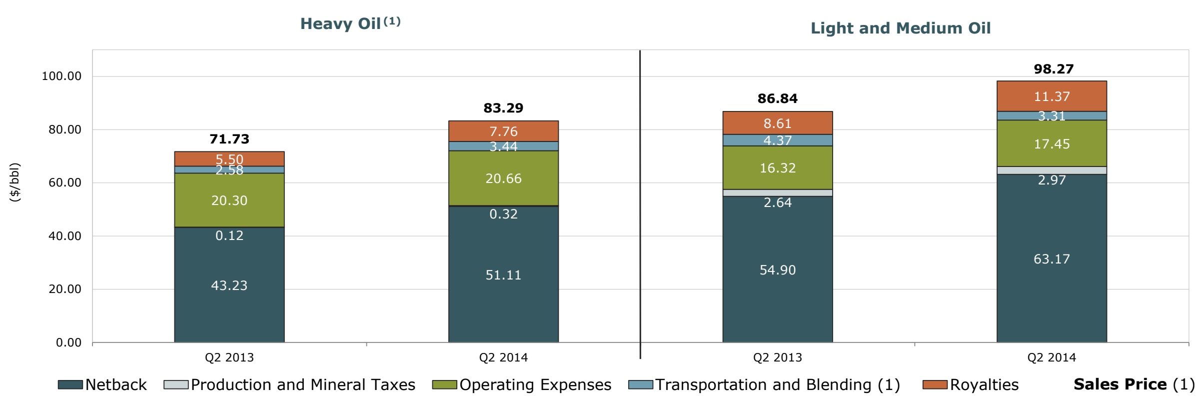
Primary drivers of our operating costs in the second quarter of 2014 were for workforce, workover activities, repairs and maintenance, electricity and chemical consumption. Our operating costs increased $3 million, or $0.73 per barrel.

Operating costs increased to $18.89 per barrel, primarily due to:

- Increased workforce costs due to an increase in long-term incentive costs, consistent with the rise in our share price;
- Higher chemical costs associated with polymer consumption and price related to the polymer flood programs; and
- Increased repairs and maintenance activities related to well optimizations.

The increases in our crude oil operating costs were partially offset by declines in operating costs due to the sale of Lower Shaunavon and Bakken assets, in addition to lower electricity and workover costs.

Operating Netbacks



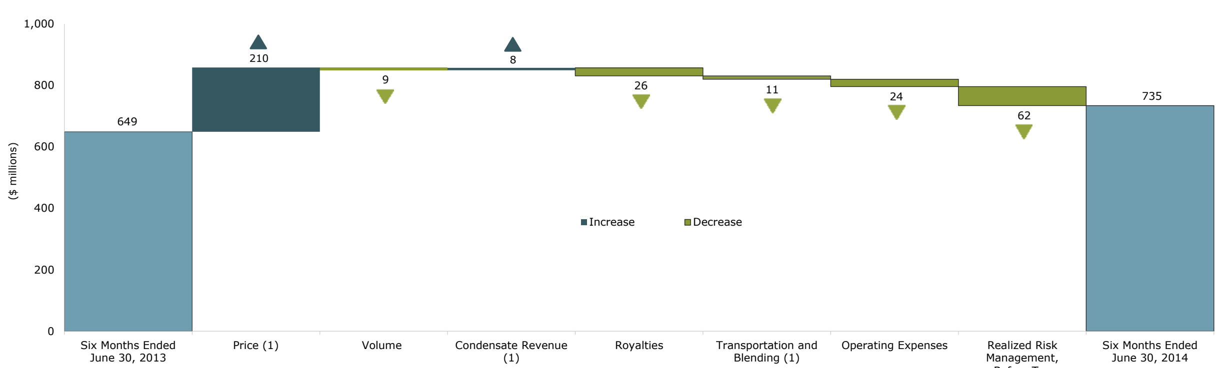
(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $17.70 per barrel in the second quarter (2013 – $16.72 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

Risk Management

Risk management activities in the second quarter resulted in realized losses of $19 million (2013 – realized gains of $10 million), consistent with average benchmark prices exceeding our contract prices.

Six Months Ended June 30, 2014 Compared With June 30, 2013

Operating Cash Flow Variance



(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.

Revenues

Pricing

In the first half of the year, our average crude oil sales price increased 21 percent to $87.72 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

	Six Months Ended June 30,		
(barrels per day)	**2014**	**Percent Change**	2013
Pelican Lake	**24,794**	**4%**	23,824
Other Heavy Oil	**15,756**	**(4)%**	16,497
Total Heavy Oil	**40,550**	**1%**	40,321
Light and Medium Oil	**34,966**	**(6)%**	37,317
NGLs	**1,121**	**17%**	961
	76,637	**(2)%**	78,599

Increased production related to our successful horizontal well performance in southern Alberta and higher production at Pelican Lake, was offset by expected natural declines and the sale of our Lower Shaunavon and Bakken assets.

Condensate

On a year-to-date basis the value of condensate increased $8 million. The proportion of the cost of condensate recovered increased on a year-to-date basis, consistent with the narrowing of the WCS-Condensate differential.

Royalties

Royalties increased $26 million largely due to a rise in realized prices, and an increase in sales volumes at Pelican Lake, partially offset by lower sales volumes at our other conventional properties. The effective crude oil royalty rate during the first six months of the year was 10.0 percent (2013 – 9.2 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $11 million in the first six months of the year. The cost of condensate increased by $8 million as discussed in the Revenues section. Transportation costs rose $3 million due to higher pipeline and storage costs related to our Pelican Lake property, partially offset by reduced transportation costs from lower sales volumes at our other conventional properties.

Operating

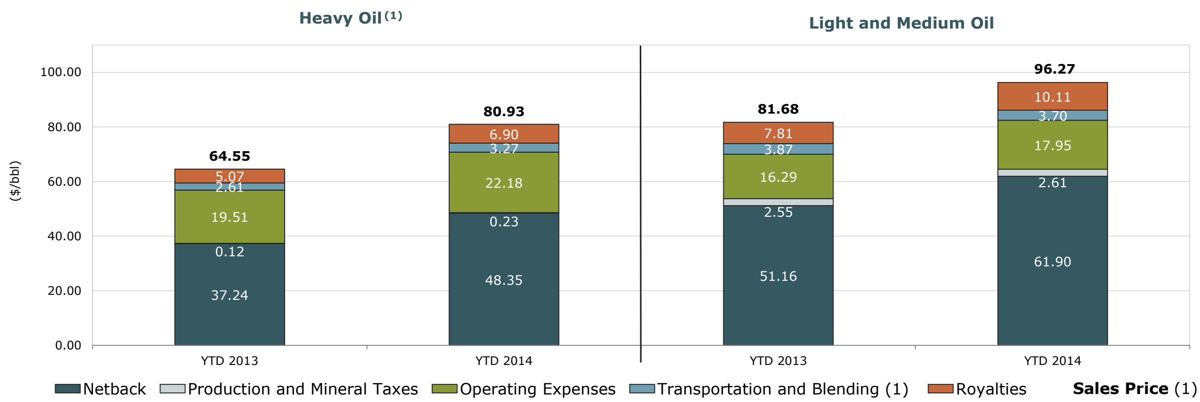
Year to date, operating costs were predominantly composed of workover activities, workforce, electricity costs and repairs and maintenance. Operating costs rose $24 million, or $2.22 per barrel.

Operating costs increased to $19.95 per barrel, primarily due to:

- Higher chemical costs associated with polymer consumption and price related to the polymer flood programs;
- Increased workforce costs related to an increase in long-term incentive costs, consistent with the rise in our share price; and
- Higher workover and repair and maintenance activities related to well optimizations.

Higher crude oil operating costs were partially offset by declines in operating costs due to the sale of Lower Shaunavon and Bakken assets, in addition to lower electricity costs.

Operating Netbacks



(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $17.63 per barrel on a year-to-date basis (2013 – $17.33 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

Risk Management

In the first six months of the year, risk management activities resulted in realized losses of $32 million (2013 – realized gains of $30 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Gross Sales	**214**	164	**398**	319
Less: Royalties	**3**	2	**6**	4
Revenues	**211**	162	**392**	315
Expenses				
Transportation and Blending	**4**	4	**9**	11
Operating	**52**	55	**101**	107
Production and Mineral Taxes	**7**	-	**6**	1
(Gain) Loss on Risk Management	**1**	(9)	**1**	(27)
Operating Cash Flow (1)	**147**	112	**275**	223
Capital Investment	**4**	4	**11**	12
Operating Cash Flow Net of Related Capital Investment	**143**	108	**264**	211

(1) *Non-GAAP measure defined in this MD&A.*

Operating Cash Flow from natural gas continues to help fund growth opportunities in our Oil Sands segment.

Three and Six Months Ended June 30, 2014 Compared With June 30, 2013

Revenues

Pricing

In the second quarter and the first half of the year, our average natural gas sales price increased $1.38 per Mcf to $4.88 per Mcf and $1.30 per Mcf to $4.68 per Mcf, respectively. The increases are consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased six percent to 484 MMcf per day in the second quarter of 2014 and declined nine percent to 471 MMcf per day on a year-to-date basis, primarily due to expected natural declines.

Royalties

Royalties increased in the second quarter of 2014 and on a year-to-date basis, as a result of higher prices, despite production declines. The average royalty rate in the second quarter was 1.7 percent (2013 – 1.2 percent) and 1.5 percent (2013 – 1.4 percent) on a year-to-date basis. Most of our natural gas production is located on fee lands where we hold mineral rights, which results in mineral tax being recorded within production and mineral taxes.

Expenses

Transportation

In the three months ended June 30, 2014, transportation costs remained consistent and declined $2 million on a year-to-date basis as a result of lower production volumes.

Operating

In the second quarter and for the first half of the year, our operating expenses were primarily composed of property taxes and lease costs, workforce and repairs and maintenance. During the quarter, operating expenses decreased $3 million primarily due to natural production declines, decreases in the cost of electricity, and lower repairs and maintenance costs, partially offset by higher property taxes and lease costs. On a year-to-date basis, operating expenses decreased $6 million due to natural production declines, lower repairs and maintenance costs, and declines in electricity pricing and consumption, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities resulted in realized losses of $1 million in the second quarter and on a year-to-date basis (2013 – realized gains of $9 million and $27 million, respectively), consistent with the average benchmark price exceeding our contract prices.

Conventional – Capital Investment [1]

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Pelican Lake	**68**	111	**139**	251
Other Heavy Oil	**14**	39	**49**	71
Light and Medium Oil	**67**	91	**224**	249
Natural Gas	**4**	4	**11**	12
	153	245	**423**	583

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

Capital investment in the first half of 2014 was primarily composed of spending on tight oil development, facilities work, and on infill drilling, maintenance capital and facilities upgrades at Pelican Lake associated with the expansion of the polymer flood. Spending on natural gas activities continues to be managed in response to the natural gas price environment.

The decline in capital investment at Pelican Lake reflects our decision to align spending with the more moderate production ramp-up associated with the initial results of the polymer flood program.

Conventional Drilling Activity

(net wells, unless otherwise stated)	Six Months Ended June 30, 2014	2013
Crude Oil	**66**	95
Recompletions	**354**	317
Gross Stratigraphic Test Wells	**14**	19
Other [1]	**24**	40

(1) Includes dry and abandoned, observation and service wells.

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are primarily related to lower-risk Alberta coal bed methane development.

Future Capital Investment

In 2014, Pelican Lake capital investment is forecast to be between $230 million and $250 million with spending mainly focused on infill drilling, pipeline construction and maintenance capital for the polymer flood.

Capital investment on other Conventional crude oil properties, which will be focused on tight oil development and facilities work, is forecast to be between $540 million and $590 million.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves as estimated by our independent qualified reserves evaluators. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by total proved reserves.

Conventional DD&A decreased $53 million and $100 million for the three and six months ended June 30, 2014, respectively. The decreases were primarily due to the impairment loss recorded in 2013 and a decline in sales volumes.

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 that impacted our Refining and Marketing segment in the second quarter of 2014 compared with 2013 include:

- Refined product output increasing as a result of an unplanned hydrocracker outage in 2013 and the timing of the planned turnarounds in 2014 as compared to 2013; and
- Operating Cash Flow decreasing 32 percent to $220 million primarily due to declines in market crack spreads and higher heavy crude oil feedstock costs, partially offset by higher refined product output.

Refinery Operations (1)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	**2014**	2013
Crude Oil Capacity (2) (Mbbls/d)	**460**	457	**460**	457
Crude Oil Runs (Mbbls/d)	**466**	439	**433**	428
Heavy Crude Oil	**221**	230	**208**	214
Light/Medium	**245**	209	**225**	214
Refined Products (Mbbls/d)	**489**	457	**458**	448
Gasoline	**240**	221	**228**	223
Distillate	**155**	145	**142**	139
Other	**94**	91	**88**	86
Crude Utilization (percent)	**101**	96	**94**	94

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity of Wood River increased effective January 1, 2014.

On a 100 percent basis, our refineries have capacity of approximately 460,000 gross barrels per day of crude oil, excluding NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil, and capacity of 45,000 gross barrels per day of NGLs. The ability to refine heavy crude oil demonstrates our ability to economically integrate our heavy crude oil production. The discount of WCS relative to WTI continues to benefit our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In the three months ended June 30, 2014, reliable refinery performance resulted in an increase to crude oil runs, refined product output and crude utilization as compared to 2013. In 2013, our refinery operations were negatively impacted by an unplanned hydrocracker outage and the completion of the planned Borger turnaround in the second quarter of 2013. The 2014 planned turnaround at Borger was completed in the first quarter.

In the first half of the year, our crude oil runs and our refined product output increased slightly over 2013. Reliable refinery performance in the second quarter of 2014 offset the unplanned hydrocracker outage in 2013. Crude utilization remained consistent as a result of the increase in our 2014 refinery capacity. While total refined product output increased, the proportion of gasoline, distillate and other refined product output remained relatively the same in the second quarter of 2014 and on a year-to-date basis.

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process a wide slate of crude oils, a feedstock cost advantage is created by processing less expensive crude oil. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit. The amount of heavy crude oil processed in 2014 decreased as a result of processing higher volumes of medium crude oil due to more favourable economics.

Financial Results

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Revenues	**3,483**	3,078	**6,741**	6,024
Purchased Product	**3,098**	2,616	**5,918**	4,893
Gross Margin	**385**	462	**823**	1,131
Expenses				
Operating	**165**	134	**363**	270
(Gain) Loss on Risk Management	**-**	4	**(5)**	8
Operating Cash Flow (1)	**220**	324	**465**	853
Capital Investment	**46**	26	**69**	51
Operating Cash Flow Net of Capital Investment	**174**	298	**396**	802

(1) Non-GAAP measure defined in this MD&A.

Gross Margin

In the second quarter and the first half of the year, the gross margin for the Refining and Marketing segment declined 17 percent and 27 percent, respectively. This was primarily due to the decline in market crack spreads, consistent with the narrowing of the Brent-WTI differential; higher heavy crude oil feedstock costs, consistent with the increase in the WCS price; and higher operating costs as described below. The declines were partially offset by an increase in refined product output primarily due to an unplanned hydrocracker outage in 2013. In addition, refined product output in the second quarter was higher as a result of the timing of the 2014 planned turnarounds and maintenance as compared to 2013.

Our refineries do not blend renewable fuels into the motor fuel products we produce and consequently we are obligated to purchase Renewable Identification Numbers ("RINs"). In the second quarter of 2014, the cost of our RINs was $30 million, a decrease from 2013 (2013 – $54 million). On a year-to-date basis, the cost of our RINs was $56 million (2013 – $77 million). These decreases are consistent with the decline in the ethanol RINs benchmark price. This cost remains a minor component of our total refinery feedstock costs.

Operating

Primary drivers of operating costs in the second quarter of 2014 and on a year-to-date basis were maintenance, labour, utilities and supplies. Operating costs increased 23 percent (YTD – 34 percent), primarily due to higher costs related to planned maintenance and turnaround activities and an increase in utility costs resulting from a rise in natural gas and electricity costs.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Wood River Refinery	**23**	13	**34**	26
Borger Refinery	**23**	13	**35**	25
	46	26	**69**	51

Capital expenditures in 2014 focused on capital maintenance and refinery reliability and safety projects. In the first quarter of 2014, we and our partner sanctioned the Wood River debottleneck project. We are currently awaiting permit approval, which is anticipated in the fourth quarter of 2014, and planned start-up of the project is anticipated in the first quarter of 2016.

In 2014, we expect to invest between $150 million and $160 million mainly related to routine safety initiatives, meeting new low sulphur (Tier III) gasoline requirements and additional capital investments expected to enhance returns at the Wood River Refinery.

DD&A

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased $5 million in the second quarter of 2014 and $12 million on a year-to-date basis, primarily due to the change in the US$/C$ foreign exchange rate.

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 the unrealized mark-to-market gains and losses on the long-term power purchase contract. In the second quarter of 2014, our risk management activities resulted in $11 million of unrealized losses, before tax (2013 – $26 million of unrealized gains, before tax). On a year-to-date basis, we had $15 million of unrealized gains, before tax from risk management activities (2013 – $204 million of unrealized losses, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2014**	2013	**2014**	2013
General and Administrative	**102**	82	**211**	165
Finance Costs	**102**	124	**232**	247
Interest Income	**(25)**	(23)	**(27)**	(50)
Foreign Exchange (Gain) Loss, Net	**(187)**	96	**(40)**	148
Research Costs	**4**	6	**6**	9
(Gain) Loss on Divestiture of Assets	**(20)**	-	**(20)**	-
Other (Income) Loss, Net	**(1)**	(2)	**(2)**	-
	(25)	283	**360**	519

Expenses

General and Administrative

In 2014, primary drivers of our general and administrative expenses were staffing costs, long-term incentive costs and office rent. General and administrative expenses increased in the second quarter of 2014 and on a year-to-date basis by $20 million and $46 million, respectively, primarily due to higher long-term incentive costs, consistent with the increase in our share price, and higher staffing 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. Finance costs decreased $22 million and $15 million in the three and six months ended June 30, 2014, respectively. The decreases were primarily due to lower interest incurred on the Partnership Contribution Payable, partially offset by higher unwinding of the discount on decommissioning liabilities and higher interest expenses on long-term debt resulting primarily from the weakening of the Canadian dollar.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the second quarter was 4.9 percent (2013 – 5.3 percent) and for the six months ended June 30, 2014 was 5.0 percent (2013 – 5.3 percent).

Foreign Exchange

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2014**	2013	**2014**	2013
Unrealized Foreign Exchange (Gain) Loss	**(181)**	84	**(38)**	134
Realized Foreign Exchange (Gain) Loss	**(6)**	12	**(2)**	14
	(187)	96	**(40)**	148

The majority of unrealized gains in the second quarter of 2014 stem from translation of our U.S. dollar denominated debt.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A for the second quarter was $21 million (2013 – $20 million) and $41 million on a year-to-date basis (2013 – $39 million).

Income Tax Expense (Recovery)

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2014**	2013	**2014**	2013
Current Tax				
Canada	**(10)**	57	**33**	87
U.S.	**3**	4	**35**	58
Total Current Tax	**(7)**	61	**68**	145
Deferred Tax	**216**	40	**252**	79
	209	101	**320**	224
Effective Tax Rate	**25%**	36%	**27%**	39%

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. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation. A provision for income taxes on earnings in the interim periods is accrued using the income tax rate that would be applicable to the expected total annual earnings.

The 2014 provision for income tax includes the effect of a favourable adjustment related to prior years, which has minimal impact on total tax. In the second quarter and the first half of the year, current income tax decreased $68 million and $77 million, respectively. The decline was primarily due to a favourable adjustment related to prior periods and a decrease in U.S. operating cash flow, partially offset by an increase in Conventional operating cash flow. Deferred income tax increased $176 million and $173 million, respectively. The increase in deferred income tax resulted from an increase in Canadian timing differences arising from increased Oil Sands income, the effect of the favourable adjustment to current tax related to prior years (as described above), offset by a decrease in the reversal of U.S. timing differences in 2014. Given expected levels of income in the U.S. in 2014, the residual pool of U.S. federal net operating losses is expected to be substantially claimed in 2014.

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 Canadian statutory tax rate as it reflects higher U.S. tax rates on U.S. sources of income and permanent differences.

The decrease in our effective tax rate in the second quarter of 2014 and on a year-to-date basis is primarily due to lower levels of U.S. source income in 2014.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2014**	2013	**2014**	2013
Net Cash From (Used In)				
Operating Activities	**1,109**	828	**1,566**	1,723
Investing Activities	**(692)**	(803)	**(3,089)**	(1,706)
Net Cash Provided (Used) Before Financing Activities	**417**	25	**(1,523)**	17
Financing Activities	**(471)**	(183)	**(225)**	(349)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(1)**	5	**56**	(3)
Increase (Decrease) in Cash and Cash Equivalents	**(55)**	(153)	**(1,692)**	(335)

	As At	
($ millions)	**June 30, 2014**	December 31, 2013
Cash and Cash Equivalents	**760**	2,452

Operating Activities

Cash from operating activities was $281 million higher in the second quarter of 2014 primarily due to the increase in Cash Flow as discussed in the Financial Results section of this MD&A. Year to date, there was a decrease of $157 million in cash from operating activities primarily due to the change in non-cash working capital, partially offset by the increase in Cash Flow as discussed in the Financial Results section of this MD&A.

Excluding risk management assets and liabilities and assets and liabilities held for sale, we had working capital of $1,019 million at June 30, 2014 compared to $1,957 million at December 31, 2013. 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 of 2014 was $111 million lower (year to date – increase of $1,383 million). The decrease in the second quarter was primarily due to proceeds received on the divestiture of our Bakken asset and a reduction in capital expenditures. The year-to-date increase in cash used in investing activities was predominately due to the prepayment of the US$1.4 billion Partnership Contribution Payable in March 2014.

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 $0.2662 per share, an increase of 10 percent from 2013 (2013 – $0.242 per share). Year-to-date dividend payments were $403 million (2013 – $367 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 increased $288 million primarily due to the net repayment of short-term borrowings. In the six months ended June 30, 2014, cash flow used in financing activities declined $124 million as a result of short-term borrowings, partially offset by the increase in dividends paid.

Our long-term debt was $5,018 million at June 30, 2014 with no principal payments due until October 2019 (US$1.3 billion). The $21 million increase in long-term debt from December 31, 2013 is primarily related to foreign exchange.

As at June 30, 2014, we are in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

We expect cash flow from our crude oil, natural gas and refining operations to fund a significant portion of our cash requirements over the next decade. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity or management of our asset portfolio. The following sources of liquidity are available as at June 30, 2014.

($ millions)	Amount	Term
Cash and Cash Equivalents	**760**	**Not Applicable**
Committed Credit Facility	**2,848**	**November 2017**
U.S. Base Shelf Prospectus (1)	**US$2,000**	**July 2016**
Canadian Base Shelf Prospectus (1)	**1,500**	**July 2016**

(1) Availability is subject to market conditions.

We have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of outstanding commercial paper.

On June 24, 2014, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion, which replaced the U.S. base shelf prospectus dated June 6, 2012, as amended May 9, 2013. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at June 30, 2014, no notes have been issued under this U.S. base shelf prospectus.

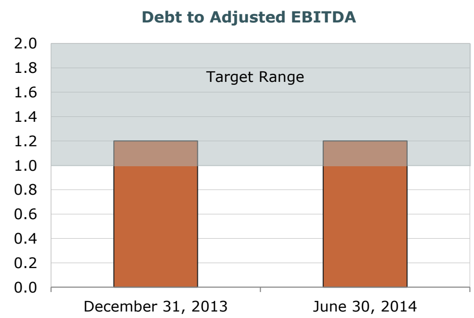
On June 25, 2014, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion, which replaced the Canadian base shelf prospectus dated May 24, 2012. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at June 30, 2014, no medium term notes have been issued under this Canadian base shelf prospectus.

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 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, calculated on a trailing 12 month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	**June 30, 2014**	December 31, 2013
Debt to Capitalization	**33%**	33%
Debt to Adjusted EBITDA (times)	**1.2x**	1.2x

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, 2014, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges. 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, 2014, 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.

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 entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. Refer to the notes of the interim Consolidated Financial Statements for more details.

Total Outstanding Common Shares and Stock-Based Compensation Plans

As at June 30, 2014	Units (thousands)
Common Shares	**757,034**
Stock Options	
NSRs	**41,290**
TSARs	**4,116**
Cenovus Replacement TSARs	**3**
Encana Replacement TSARs	**48**
Other Stock-Based Compensation Plans	
PSUs	**7,110**
DSUs	**1,274**

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, see the notes to the interim Consolidated Financial Statements.

We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions.

Legal Proceedings

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

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management section of our 2013 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 the risks identified in our 2013 annual MD&A has not changed substantially since December 31, 2013. In addition, no new material risks were identified.

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, 2013. The following provides an update on our commodity price risk management.

Commodity Price Risk

Fluctuations in commodity prices create volatility in our financial performance. Commodity prices are impacted by a number of factors including global and regional supply and demand, transportation constraints, weather conditions and availability of 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 activities including integration, financial hedges and physical contracts. We have a variety of instruments and strategies available to us within our financial hedges and physical contracts, such as swaps, futures, options, collars, differentials and fixed-price contracts, that will be utilized as market conditions warrant. For further details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see the notes to the interim and annual Consolidated Financial Statements. The financial impact is summarized below:

Financial Impact of Risk Management Activities

	Three Months Ended June 30,					
	2014			2013		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**52**	**12**	**64**	(11)	(21)	(32)
Natural Gas	**1**	**(3)**	**(2)**	(8)	(6)	(14)
Refining	**-**	**3**	**3**	4	3	7
Power	**2**	**(1)**	**1**	(5)	(2)	(7)
(Gain) Loss on Risk Management	**55**	**11**	**66**	(20)	(26)	(46)
Income Tax Expense (Recovery)	**(14)**	**(3)**	**(17)**	4	5	9
(Gain) Loss on Risk Management, After Tax	**41**	**8**	**49**	(16)	(21)	(37)

	Six Months Ended June 30,					
	2014			2013		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**86**	**(14)**	**72**	(54)	169	115
Natural Gas	**1**	**(2)**	**(1)**	(27)	36	9
Refining	**(4)**	**2**	**(2)**	8	1	9
Power	**2**	**(1)**	**1**	(5)	(2)	(7)
(Gain) Loss on Risk Management	**85**	**(15)**	**70**	(78)	204	126
Income Tax Expense (Recovery)	**(21)**	**4**	**(17)**	18	(52)	(34)
(Gain) Loss on Risk Management, After Tax	**64**	**(11)**	**53**	(60)	152	92

In the quarter and the first half of the year, management of commodity price risk resulted in realized losses on crude oil financial instruments, consistent with average benchmark prices exceeding our contract prices.

In the quarter, we recognized unrealized losses on our crude oil financial instruments as a result of the changes in forward prices compared with prices at the end of the prior quarter and changes in prices for transactions executed during the quarter, partially offset by the realization of settled positions and the widening of forward light/heavy differentials.

On a year-to-date basis, we recognized unrealized gains on our crude oil financial instruments as a result of the realization of settled positions, the widening of forward light/heavy differentials, partially offset by changes in forward prices compared with prices at the end of the prior year and changes in prices for transactions executed during the period.

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 2013 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 preparation 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, 2013.

Critical Accounting Judgments in Applying Accounting Policies

Critical accounting 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 our annual and interim Consolidated Financial Statements and accompanying notes. There have been no changes to our critical judgments used in applying accounting policies in the first six months of 2014. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2013.

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 in the first six months of 2014. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2013.

Future Accounting Pronouncements

New and Amended Standards and Interpretations Adopted

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2014, we adopted, as required, amendments to IAS 32, *"Financial Instruments: Presentation"* ("IAS 32"). The amendments clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. IAS 32 did not impact the consolidated financial statements.

New Standards and Interpretations not yet Adopted

Revenue Recognition

In May 2014, the IASB published IFRS 15, *"Revenue From Contracts With Customers"* ("IFRS 15") replacing IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. We are currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

Financial Instruments

On July 24, 2014, the IASB issued IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace International Accounting Standard 39, *"Financial Instruments: Recognition and Measurement*". IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

Additional Standards

A description of additional standards and interpretations that will be adopted by the Company in future periods can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2013.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") in the three months ended June 30, 2014 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. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, our CR approach and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. Our CR policy and CR report is available on our website at cenovus.com. Our 2013 CR report was issued in July 2014.

In June 2014, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the third year in a row and for the fourth consecutive year by Corporate Knights magazine as one of the 2014 Best Corporate Citizens in Canada. We were also included in the Euronext Vigeo World 120 Index. This index recognizes the top 120 companies globally for their high degree of control of corporate responsibility risk and contributions to sustainable development.

In February 2014, Cenovus was named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the second year in a row. In January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index. Corporate Knights magazine also named Cenovus to their 2014 Global 100 clean capitalism ranking for the second consecutive year, as announced during the World Economic Forum in Davos, Switzerland in January 2014.

These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

OUTLOOK

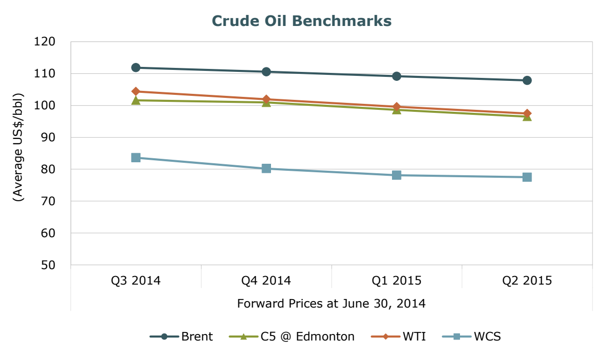
We continue to move forward on our business plan targeting net crude oil production, including our conventional oil operations, of more than 500,000 barrels per day. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Telephone Lake and Grand Rapids. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach. This approach will be driven by technology, innovation and continued respect for the health and safety of our employees and contractors, with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

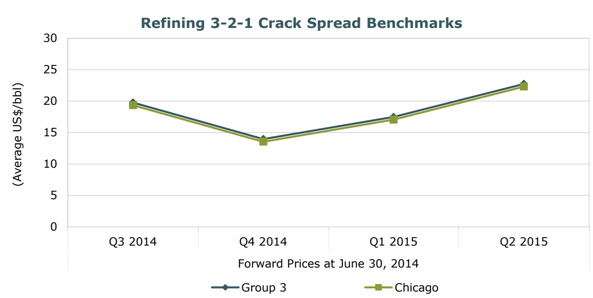
The following outlook commentary herein is focused on the next twelve months.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

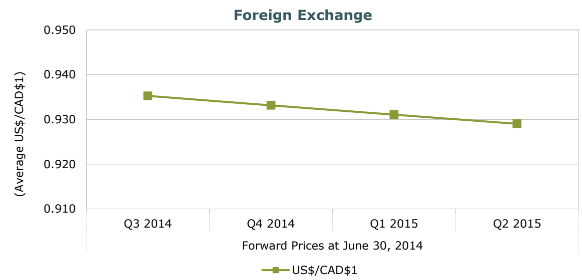
- We expect the general outlook for crude oil prices will continue to be tied to global economic growth, the pace of North American supply growth and production interruptions. Economic indicators suggest an improvement in crude oil demand growth from the U.S. as the adverse weather impacts experienced in the first half of 2014 dissipate. North American crude oil supply growth is expected to continue at a strong, but moderating pace. Global supply disruptions are difficult to predict and materially impact the price of Brent crude oil. Recent unrest in Iraq has driven Brent crude oil prices higher. Given the uncertainty in Iraq and increased risk of supply outages, we expect Brent crude oil prices in 2014 to be higher than 2013;
- The Brent-WTI differential has narrowed from 2013 as new pipeline capacity from Cushing to the U.S. Gulf Coast has reduced inland congestion. Growing tight oil supply should reduce the need for imports to the U.S. and create occasional congestion issues. We expect that this, coupled with the increased risk of geopolitical outages, will result in wider Brent-WTI differentials;
- The WTI-WCS differential will continue to be set by the marginal transportation cost to the U.S. Gulf Coast. Differentials will likely remain close to current levels as a result of excess rail capacity from rail infrastructure additions. The differential may be volatile due to uncertainty around the timing of upcoming rail and pipeline infrastructure additions; and
- With refinery turnaround season complete, we expect a slight decline in inland refining crack spreads in the short term.





Natural gas prices are expected to remain consistent to prices experienced in the first half of the year, with the potential for volatility based on weather. As storage levels return to more normal levels, we expect a modest weakening of pricing.

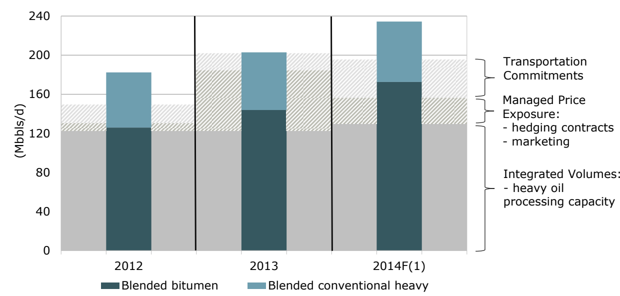
Foreign exchange prices have strengthened in the second quarter of 2014 as compared to the first quarter. The average foreign exchange forward price is US$0.932/C$1 over the next four quarters. Overall, the Canadian dollar remains relatively weak, which has a positive impact on our revenues and Operating Cash Flow.



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 oil 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 tidewater markets.

Protection Against Canadian Congestion



(1) *Expected gross production capacity.*

Key Priorities for 2014

Our key priorities for 2014 remain unchanged from 2013.

Market Access

We are focused on near and mid-term strategies to broaden market access for our crude oil production. 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 crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions, by supporting industry transportation projects as well as new and expanded market development initiatives for our crude oil.

Attacking Cost Structures

We continue to take aim at cost structures across the organization to maintain our track record of cost efficiency. 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 are actively identifying opportunities in supply chain management to further reduce 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 our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A.

ADVISORY

Oil and Gas Information

The estimates of reserves and resources data and related information were prepared effective December 31, 2013 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2014 price forecast. For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2013.

Barrels of Oil Equivalent - Certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

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", "goal", "outlook", "potential", "may", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related milestones and schedules, projected future value or net asset value, projections for 2014 and future years, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, expected reserves and contingent and prospective resources, broadening market access, improving cost structures, 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.

2014 guidance is based on an average diluted number of shares outstanding of approximately 757 million. It assumes: Brent US$105.00/bbl, WTI of US$102.00/bbl; Western Canada Select of US$76.00/bbl; NYMEX of US$4.00/MMBtu; AECO of $3.30/GJ; Chicago 3-2-1 crack spread of US$13.50/bbl; exchange rate of $0.98 US$/C$. For the period 2015 to 2023, assumptions include: Brent US$105.00-US$110.00; WTI of US$100.00-US$106.00/bbl; Western Canada Select of US$81.00-US$91.00/bbl; NYMEX of US$4.25-US$4.75/MMBtu; AECO of $3.70-$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$13.00; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 782 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 relationships 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; realized 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, including sufficient crude-by-rail or other alternate 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 consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our AIF or Form 40-F for the year ended December 31, 2013 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

BOE	barrel of oil equivalent
MBOE	thousand barrel of oil equivalent
TM	Trademark of Cenovus Energy Inc.