Second Quarter
2015

cenovus ENERGY

Cenovus announces second quarter results, additional measures to build shareholder value

Second quarter highlights

- Combined oil sands production up 5% compared with second quarter of 2014
- Oil sands per-unit operating cost improvement of 30% from second quarter of 2014
- Gross cash proceeds of $3.3 billion from royalty and fee land business sale, received in July
- Second quarter cash flow of $0.89 per share, excluding the impact of a one-time cash tax charge of $0.31 per share

Production & financial summary			
(For the period ended June 30) Production (before royalties)	**2015** **Q2**	2014 Q2	% change
Oil sands (bbls/d)	**130,734**	124,827	5
Conventional oil[1] (bbls/d)	**69,220**	76,861	-10
Total oil (bbls/d)	**199,954**	201,688	-1
Natural gas (MMcf/d)	**450**	507	-11
Financial ($ millions, except per share amounts)			
Cash flow[2]	**477**	1,189	-60
Per share diluted	**0.58**	1.57	
Operating earnings[2]	**151**	473	-68
Per share diluted	**0.18**	0.62	
Net earnings	**126**	615	-80
Per share diluted	**0.15**	0.81	
Capital investment	**357**	686	-48

[1] Includes natural gas liquids (NGLs).

[2] Cash flow and operating earnings are non-GAAP measures as defined in the Advisory. See also the earnings reconciliation summary in the operating earnings table.

Strategic update highlights

- On track to achieve approximately $280 million in 2015 cost reductions, 40% greater than initially targeted
- Targeting between 300 and 400 job reductions in Calgary in second half of 2015
- Third quarter dividend reduction of 40%; temporary discount on Dividend Reinvestment Plan (DRIP) discontinued
- Priority focus on expanding existing oil sands projects but at a more moderate pace of growth than in the past
- Investment in deferred oil sands expansions being considered for 2016

"We are planning for West Texas Intermediate oil prices to be approximately $65 per barrel through 2017," said Brian Ferguson, Cenovus President & Chief Executive Officer. "But even at $50 per barrel, we believe we are well positioned to be able to internally fund our reduced dividend as well as our sustaining and growth capital without compromising our balance sheet."

Strategic update

Calgary, Alberta (July 30, 2015) – Cenovus Energy Inc. (TSX: CVE) (NYSE: CVE) continues to deliver strong operational performance, with dependable oil sands production growth and meaningful cost reductions. The company has undertaken a number of significant initiatives to strengthen its financial resilience and is now taking further steps intended to enhance value for shareholders during this extended period of low oil prices and market volatility. The company's actions are aimed at maintaining its balance sheet and helping to ensure Cenovus is operating with the greatest efficiency. In addition, Cenovus has adjusted its previous capital investment strategy and plans to take a more moderate approach to the growth of its oil sands assets.

Cenovus has already delivered on a number of its 2015 commitments, including reducing capital and discretionary spending, achieving meaningful improvements in its operating, capital and general and administrative (G&A) costs, making initial workforce reductions, and crystallizing significant value for shareholders by selling its royalty and fee land business at an attractive price. Today, Cenovus is announcing further measures, including an adjustment to its dividend and additional cost-cutting initiatives, to further align the company with the economic realities facing the oil and gas industry and help ensure it can remain competitive with oil production across North America.

"We've taken a number of decisive steps to help ensure financial resilience during a prolonged period of lower oil prices," said Ferguson. "As a result of these initiatives and the operational progress the company has made, we are now in an even stronger position to remain cost competitive and potentially resume investing in high-return growth projects."

Dividend update

With the expectation of a prolonged period of low oil prices and the cash flow impact from the sale of its royalty and fee land business, Cenovus is reducing its dividend by 40%. The Board of Directors has declared a third quarter dividend of $0.16 per share, payable on September 30, 2015 to common shareholders of record as of September 15, 2015. Based on the July 29, 2015 closing share price on the Toronto Stock Exchange of $18.61, this represents an annualized yield of about 3.4%. Declaration of dividends is at the sole discretion of the Board and will continue to be evaluated on a quarterly basis. Over the long term, Cenovus intends to target a dividend payout ratio of 20% to 25% of after-tax cash flows. With this dividend reduction, the company is on track to be within its target range for 2015.

Cenovus has discontinued the temporary discount on its Dividend Reinvestment Plan (DRIP). The discount, which allowed shareholders to reinvest their dividends in Cenovus common shares at 3% below current market prices, was designed to conserve cash. Cenovus now believes it has adequate liquidity to manage through the low oil price environment, and the discount on the DRIP is no longer required. While the DRIP will remain in place, in future, common shares acquired under the DRIP will be purchased in the open market, eliminating the dilution caused by the issuance of shares from Treasury.

Cost reductions

Cenovus continues to make solid progress attacking cost structures across the entire company to reduce its spend and create sustainable cost improvements. The company previously announced a target of $200 million in upstream operating, capital and G&A cost savings for 2015, which were largely achieved within the first six months of the year. As a result, the company is increasing its cost-cutting expectation for 2015 to approximately $280 million, 40% higher than its initial target.

Part of the company's cost-cutting efforts has focused on workforce. In February, Cenovus announced initial plans to reduce its workforce by approximately 800 positions to align with capital budget reductions for the year. The company has since identified 300 to 400 positions at its Calgary offices that are expected to be eliminated before the end of 2015. These positions are no longer required because of a decrease in work due to the continued low oil price environment. Cenovus also intends to review the company's compensation, benefits and time-off practices to ensure they align with current and anticipated market conditions. The cost savings associated with these additional workforce efficiencies are expected to be at least $100 million annually. Because the full impact of these workforce savings is still being finalized and will likely be more evident in 2016, they have not been included in the company's $280 million overall cost-reduction target for this year.

Cenovus is also planning for additional staff reductions at its field operations in early 2016, as the company continues to identify even greater workforce efficiencies. Details of these additional reductions will be provided at a later date.

"Reducing the size of our talented workforce was not an easy decision, but it's the right one," said Ferguson. "The new economic reality for our industry includes low oil prices and competition from light tight oil in the U.S. To help ensure our continued success, we must adapt by reducing all of our costs and becoming as efficient as possible."

Specific examples of cost savings already achieved or underway this year include:

- The centralization of Cenovus's supply chain management team to allow for greater standardization of supplies and services, a reduction in the overall number of suppliers and more effective management of the company's spend
- An innovation in the design of well pads at oil sands sites to reduce the amount of area and infrastructure needed, which is anticipated to result in significant sustained capital and operating cost savings
- Improved drilling and completion processes
- Greater standardization of facility and infrastructure design
- Reduced supplier costs for on-site pipeline installation
- Improvements to oil sands waste disposal and handling processes

Of the company's targeted 2015 savings, about two-thirds are expected to come from operating cost improvements with the remainder related to reduced capital spending as well as lower G&A expenses. Cenovus anticipates about half of these savings will be sustainable over the long term.

More efficient organizational model

Cenovus also continues to make substantive progress with its transition to a new organizational model, which will help the company optimize its workflows, better utilize its people and expertise and achieve efficiencies that will lead to sustainable reductions in its overall cost structures. Under the new model, teams are being organized by function and aligned with the company's value chain as opposed to specific assets. Cenovus plans to have its functional model structure in place by the end of the year. The move is expected to result in additional workforce efficiencies.

Cenovus is also realigning the structure of its Leadership Team to better fit with the functional model. The planned retirements of four Executive Vice-Presidents announced this May are proceeding as expected. To minimize disruption to Cenovus's business and ensure the transitions are orderly and managed, the retiring executives will continue in varying capacities until the end of the first quarter of 2016. As a result of Cenovus's strong focus on internal succession planning, three of the vacancies on the Leadership Team are being filled by internal candidates who are being promoted to newly-restructured portfolios. In addition, an external search is well underway for a President, Upstream Oil & Gas, who will be responsible for the company's oil sands and conventional operations. Cenovus expects to have that candidate identified by September.

Disciplined capital allocation

Cenovus continues to focus on capital discipline, with its oil sands assets remaining its top priority for capital allocation. The company anticipates that 2015 capital spending will remain within its previously announced guidance of $1.8 billion to $2.0 billion.

In its first five years of operations, the company generated a compound annual production growth rate of 24% from its jointly owned Foster Creek and Christina Lake oil sands projects. In response to the company's expectations for a continued low oil-price environment, Cenovus is taking a more moderate and staged approach to expanding these assets. Rather than pursuing multiple major construction projects at the same time, the company will consider expanding existing projects and developing emerging opportunities only when it believes it can do so with the greatest efficiency and cost savings, while generating the greatest potential return for shareholders. The company is no longer targeting to achieve 500,000 barrels per day (bbls/d) of net oil production by 2021.

For the remainder of 2015, Cenovus's capital investment priorities are:

- Sustaining existing oil sands production
- Completing the ongoing Foster Creek phase G expansion
- Completing the ongoing Christina Lake optimization and phase F expansion

These projects remain on schedule and are expected to add approximately 100,000 bbls/d of incremental gross production capacity (50,000 bbls/d net) by the end of 2016, an increase of about 25% to the company's current total crude oil production volumes once the phases are at full operational capacity.

For 2016, Cenovus is considering investing capital in additional expansion projects that were deferred earlier this year. With considerable strength on its balance sheet and the sustained reductions already achieved, the company has the financial capability to resume those projects when it feels the timing is right. Those investment decisions would be based on oil price stability, continued balance sheet strength, the company's ongoing cost-cutting success as well as fiscal and regulatory certainty. Cenovus is allocating between $25 million and $30 million for the remainder of 2015 to prepare for the possibility of construction resuming on some of these projects next year.

Once a decision is made to proceed, Cenovus's priority would be to allocate capital to re-start construction at its deferred Christina Lake phase G and Foster Creek phase H expansions. The next priority would be to resume work at the Narrows Lake oil sands project. These projects have the ability to provide top-tier returns.

As with its oil sands operations, Cenovus is also taking a more moderate approach to investing in its conventional oil opportunities, with a focus on drilling projects that are considered to be relatively low risk, with short production cycle times and expected returns well in excess of the company's internal hurdle rate of 15%. As part of this strategy, Cenovus is currently directing capital to resume drilling at the company's tight oil projects in southeast Alberta, where it has experienced success in recent years, and at its Weyburn enhanced oil recovery project in Saskatchewan, which benefits from strong netbacks and returns at current prices. Cenovus has allocated $70 million, activating three rigs, to resume its conventional drilling program in the third quarter. The company has no plans to allocate additional capital to its Pelican Lake or other conventional projects this year.

Cenovus continues to believe in the long-term potential of its emerging projects, including Telephone Lake and Grand Rapids. At this time though, plans for development of these projects have been deferred, as the company continues to work on new technology and process improvements that are expected to further reduce capital and operating costs for those assets.

The company expects to provide further clarity around its capital investment plans when it releases its 2016 budget in December.

Value creation & portfolio management

During the quarter, Cenovus announced an agreement to sell Heritage Royalty Limited Partnership (HRP), a wholly owned subsidiary holding the company's royalty and fee land business. Included in the agreement were associated royalties on third-party interest volumes and on Cenovus's working interest production as well as a Gross Overriding Royalty (GORR) on the company's Pelican Lake and Weyburn production. The sale, which closed on July 29, 2015, generated gross cash proceeds of $3.3 billion, with an expected after-tax gain of approximately $1.9 billion, to be recorded in the third quarter. The proceeds further supplement Cenovus's strong balance sheet and ongoing prudent management of its finances. On a pro forma basis, including the proceeds from the sale of its royalty and fee land business, Cenovus would have had a second quarter net debt to capitalization ratio of 7%, with net debt to adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) of 0.3 times. The transaction provides the company with the flexibility to invest in projects that offer the greatest returns for shareholders over the near- and medium-term, when oil prices are expected to remain low. At current oil and gas prices, the transaction is expected to reduce Cenovus's future cash flow by approximately $120 million annually.

On June 4, 2015, Cenovus announced an agreement to purchase a crude-by-rail trans-loading facility located in Bruderheim, Alberta for approximately $75 million. The purchase supports the company's strategy of increasing transportation options to maximize access to global markets where it expects to capture higher prices for its oil. The transaction is expected to close August 31, 2015, subject to certain conditions.

Cenovus maintains an active portfolio management program, continuously assessing both acquisition and divestiture opportunities. As part of its strategy to add shareholder value, the company continues to look for opportunities to crystallize additional value from its conventional portfolio, as it did with the HRP sale. Cenovus's conventional oil and natural gas assets have historically provided reliable cash flow, well in excess of their capital investment requirements, to fund the company's oil sands expansions. As production from the oil sands assets grows and they contribute increasing free cash flow, the strategic value of some of its conventional assets has become less important than in previous years.

While Cenovus continues to believe in the value of its integrated strategy, which includes its refineries, the company has no pending plans to invest in additional downstream assets. It would consider a downstream acquisition only if it offers compelling value and strategic fit, as was identified with the recent Bruderheim rail facility transaction.

Guidance updated
Cenovus has updated its 2015 full-year guidance to reflect actual results for the first six months of the year and the company's estimates for the third and fourth quarter. The updated guidance, available at cenovus.com under "Investors," reflects Cenovus's expectations for continued strong oil sands production, as well as its improved outlook for upstream operating and G&A expenses compared with the company's previous guidance. The outlook for cash flow is also significantly improved, largely as a result of higher anticipated oil prices, partially offset by the cash flow impact from the sale of the company's royalty and fee land business. The company's 2015 capital budget remains unchanged at $1.8 billion to $2.0 billion.

Second quarter results

Cenovus continued to deliver strong operating performance in the second quarter, with incremental growth in its oil sands production. The company also continues to benefit from its integrated strategy, with operating cash flow from its jointly owned U.S. refineries up by more than one-third compared with the second quarter of 2014. In addition, the company continued to build on its efforts to cut costs, achieving significantly lower operating expenses compared with the second quarter of 2014. Cash flow in the second quarter was lower than in the same period a year earlier, largely as a result of the sharp drop in crude oil and natural gas prices. Cash flow was also negatively impacted by an acceleration of current tax payable in response to an increase in Alberta's corporate income tax rate.

Foster Creek and Christina Lake are operating very well, with average combined oil sands production of nearly 131,000 bbls/d net in the second quarter, a 5% increase from the same period a year earlier. In July, combined production averaged almost 150,000 bbls/d net, which is above the original design capacity for both operations.

Foster Creek production grew to more than 58,000 bbls/d net in the second quarter, a 3% increase from the same period of 2014, despite a shutdown of the project in the latter half of the quarter. In late May, a decision was made to undertake the precautionary evacuation and orderly shutdown of operations at both the Foster Creek and Athabasca natural gas properties due to a forest fire that caused the closure of the only access road to the projects. While the fire resulted in no damage to the Foster Creek facilities, the 11-day outage reduced second quarter oil sands production by approximately 10,500 bbls/d net (about 2,600 bbls/d net on an annualized basis). Following the restart of operations at Foster Creek, flush production contributed to record daily volumes, which has helped offset some of the production losses related to the shutdown. The flush production is expected to taper off, and the company continues to expect full-year production at Foster Creek will remain within its previously announced guidance of 62,000 bbls/d to 68,000 bbls/d net.

At Christina Lake, second quarter production averaged more than 72,000 bbls/d net, up 6% from the same period in 2014. Compared with the first quarter of 2015, production declined approximately 4,000 bbls/d net due to unplanned downtime, primarily because of a power outage. Cenovus expects full-year production volumes at Christina Lake to be above the midpoint of its previously announced guidance of 67,000 bbls/d to 74,000 bbls/d net.

Oil sands operating expenses for the quarter declined $4.64 per barrel (bbl), or 30%, compared with the same period in 2014. Non-fuel per-unit operating costs decreased due to higher production volumes, reduced workover activity (primarily due to lower-cost electric submersible pump changes) and lower repair and maintenance costs resulting from improved scheduling of work. Foster Creek's second quarter non-fuel operating expenses included approximately $2.6 million net, or $0.49/bbl, of incremental costs related to the shutdown and restart of the facility due to the forest fire. Fuel costs at Foster Creek and Christina Lake declined as a result of reduced natural gas prices and lower fuel consumption per barrel of production.

Impact of commodity prices and taxes

While crude oil benchmark prices strengthened compared with the first quarter of 2015, they remain significantly weaker than a year ago. In the second quarter, sales prices for Cenovus's crude oil and natural gas were approximately 38% lower compared with the same period in 2014. This contributed to a 42% decrease in upstream operating cash flow, which was partially offset by a 36% increase in operating cash flow from refining and marketing. Total operating cash flow declined 28% to $928 million compared with the second quarter of 2014.

Cash flow was $477 million in the second quarter, 60% lower than in the same period in 2014. In addition to lower crude oil and natural gas prices, cash flow was negatively impacted by higher than planned current income tax expense of $315 million compared with a tax recovery of $7 million in the same period a year earlier. The higher tax expense was primarily due to the acceleration in timing of income tax payable in response to the recent increase in the Alberta corporate income tax rate from 10% to 12%, effective July 1, 2015.

After investing $357 million in the second quarter, Cenovus had free cash flow of $120 million, down from $503 million in the same period a year earlier.

Oil Projects

Daily production[1]								
(Before royalties) (Mbbls/d)	**2015**		2014					2013
	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Oil sands								
Christina Lake	**72**	76	69	74	68	68	66	49
Foster Creek	**58**	68	59	68	57	57	55	53
Oil sands total	**131**	144	128	142	125	125	120	103
Conventional oil[2]	**69**	74	75	74	74	77	76	77
Total oil	**200**	218	203	216	199	202	197	179

[1] Totals may not add due to rounding.
[2] Includes NGLs production.

Oil sands

Cenovus has a substantial portfolio of oil sands assets in northern Alberta with the potential to provide decades of value creation. The two operations currently producing, Christina Lake and Foster Creek, use steam-assisted gravity drainage (SAGD), which involves drilling into the reservoir and injecting steam at low pressures to soften the thick oil, so it can be pumped to the surface. Cenovus has approval for a third major oil sands project at Narrows Lake. These projects are operated by Cenovus and jointly owned with ConocoPhillips. Cenovus also has a significant opportunity to deliver increased shareholder value over the long term through production growth from several identified emerging projects and additional future developments.

Christina Lake

Production

- Production at Christina Lake averaged 72,371 bbls/d net in the second quarter of 2015, 6% higher than in the same period a year earlier, due to the startup of new wells and improved plant and reservoir performance. In addition, Christina Lake benefited in the quarter from production at phase E, which reached design capacity during the second quarter of 2014.
- The steam to oil ratio (SOR) was 1.7, an improvement from 1.8 in the second quarter of 2014.
- Operating costs at Christina Lake were $8.32/bbl in the second quarter, down 31% from $12.08/bbl in the same period of 2014. Just under half of the reduction was due to reduced fuel costs as a result of lower natural gas prices and a decrease in fuel consumption per barrel of production.
- Non-fuel operating costs were $6.14/bbl, down 25% from $8.22/bbl in the second quarter of 2014. The decrease was due to lower repair and maintenance costs resulting from improved scheduling of work, reduced workover activity (primarily due to lower-cost electric submersible pump changes) and higher production volumes.
- The netback the company received for its Christina Lake oil production was $29.76/bbl in the second quarter, down 42% from $51.66/bbl in the same period a year earlier.

Expansions

- Cenovus's plant optimization project at Christina Lake is nearly complete. The project is designed to add additional steam generating capacity and optimize oil treating. Cenovus expects the optimization to ramp up over a period of 12 months, beginning in the fourth quarter of 2015, with total gross production capacity at Christina Lake increasing to 160,000 bbls/d as a result.
- The company is progressing construction at Christina Lake phase F. Central plant construction is expected to be complete by the end of 2015. First oil from this phase is expected in the second half of 2016. Phase G central plant construction, which is currently on hold, is more than one-third complete.
- Second quarter capital investment at Christina Lake was $161 million, compared with $183 million in the second quarter of 2014.

Foster Creek

Production

- Foster Creek production averaged 58,363 bbls/d net in the second quarter, 3% higher than in the second quarter of 2014. The increase was primarily due to additional production from phase F, which continues to ramp up on schedule. The ramp-up is expected to be complete in the first quarter of 2016, approximately 18 months following first production. After nine months of ramp-up, phase F contributed approximately 16,000 bbls/d gross in incremental production in the second quarter and is currently producing almost 23,000 bbls/d gross. The phase F plant has a gross design capacity of 30,000 bbls/d.
- The increase in second quarter production was partially offset by the temporary shutdown of operations at Foster Creek in late May and early June due to a nearby forest fire, resulting in the loss of approximately 10,500 bbls/d net for the quarter.
- The SOR at Foster Creek was 2.3 in the second quarter, an improvement from 2.6 in the same period a year earlier. The lower SOR was due, in part, to incremental production from phase F in the second quarter of 2015 compared with the same period a year earlier when wells were being started up without any associated production. The SOR also decreased as a result of improved conformance on new well pairs. Foster Creek's SOR is expected to range between 2.6 and 3.0 while expansion phases F and G are ramping up. After ramp-up, the SOR is expected to drop below 2.5.
- Operating costs at Foster Creek decreased 30% to $13.47/bbl compared with $19.38/bbl a year earlier. Approximately one-third of the decrease was due to reduced fuel costs as a result of lower natural gas prices and a decrease in fuel consumption per barrel of production.
- Non-fuel operating costs fell 28% to $10.69/bbl in the second quarter compared with $14.78/bbl in the same quarter last year. The decrease was due to reduced workover activity (primarily due to lower-cost electric submersible pump changes) and higher production volumes.
- The netback the company received for its Foster Creek oil was $23.77/bbl in the second quarter, compared with $50.15/bbl in the same period a year earlier.

Expansions

- Construction is continuing on phase G, which is anticipated to begin producing in the first half of 2016. Plant construction at phase G is approximately three-quarters complete. Phase H is currently on hold.
  Second quarter capital investment at Foster Creek was $73 million, compared with $209 million in the second quarter of 2014, down 65%.

Narrows Lake

- Cenovus believes Narrows Lake has the potential to achieve total production capacity of 130,000 bbls/d. Narrows Lake is expected to be the industry's first project to use a solvent aided process (SAP) on a commercial scale, combining butane with steam to improve oil recovery.
- In the second quarter, the company spent approximately $9 million at Narrows Lake, primarily due to initial procurement commitments, continued engineering and work to complete a camp facility that was already under construction.
- The company plans to take advantage of the slower pace of development to further optimize its engineering and execution strategy to find the most economic way to develop the project.

Emerging projects

Grand Rapids

- Cenovus continues to operate a SAGD pilot project at Grand Rapids with two producing well pairs. A third pilot well pair was drilled, completed and put on steam circulation in the second quarter. Data from these well pairs will be used to help determine the company's development plan for Grand Rapids.
- The company has completed the dismantling and storage of an existing SAGD facility that Cenovus purchased in 2014 and intends to relocate to the Grand Rapids site once the development plan has been finalized and a decision made to start investing in a commercial project, subject to more favourable conditions.
- Grand Rapids has regulatory approval for total production capacity of 180,000 bbls/d.

Telephone Lake

- Cenovus continues to review development options for Telephone Lake after receiving approval for an initial 90,000 bbls/d SAGD project from the Alberta Energy Regulator in late 2014.

Conventional oil

Cenovus has tight oil opportunities in Alberta as well as the established Weyburn operation in Saskatchewan that uses carbon dioxide injection to enhance oil recovery. Cenovus also produces conventional heavy oil from the Wabiskaw formation using polymer and water floods at its 100%-owned Pelican Lake operation in northern Alberta.

- Total conventional oil production was 69,220 bbls/d in the second quarter, down 10% from 76,861 bbls/d in the same period a year ago, primarily due to expected natural declines and the sale of non-core assets in the third quarter of 2014 as well as capital spending reductions resulting in no new drilling. The non-core assets sold had production of approximately 3,000 bbls/d in the second quarter of last year.

- Operating costs for Cenovus's conventional oil operations were $15.58/bbl in the second quarter, down 18% from $18.89/bbl in the same period of 2014. The decrease was due, in part, to lower workover costs and lower repair and maintenance expenses resulting from improved scheduling of work. In addition, waste fluid handling and trucking costs declined.
- The company invested $34 million in its conventional oil assets in the second quarter, compared with $149 million in the same period a year earlier.
- Pelican Lake continues to deliver reliable production and cash flow following the company's decision to significantly reduce capital spending and optimize operations at the project. During the second quarter, Pelican Lake produced an average of 25,053 bbls/d, a slight improvement over the same quarter of 2014. Operating costs at Pelican Lake were $15.35/bbl, a 28% reduction from the second quarter of 2014.
- The company plans to restart a portion of its conventional drilling program in the third quarter of this year, directing approximately $70 million toward the program for the remainder of 2015. This program is focused on Cenovus's tight oil assets in southern Alberta and the company's Weyburn enhanced oil recovery project in Saskatchewan.
- With reduced production associated with the divestiture of Cenovus's royalty and fee land business expected to be partially offset by production from new drilling, the company anticipates conventional oil volumes to be within its previously announced guidance of between 66,000 bbls/d and 70,000 bbls/d for 2015.

Natural Gas

Daily production								
(Before royalties) (MMcf/d)	**2015**		2014					2013
	Q2	Q1	Full Year	Q4	Q3	Q2	Q1	Full Year
Natural gas	**450**	462	488	479	489	507	476	529

Cenovus has a solid base of established, reliable natural gas properties in Alberta. The company has been managing these properties as financial assets, rather than production assets, due to their ability to generate operating cash flow well in excess of their ongoing capital investment requirements.

- Natural gas production averaged 450 million cubic feet per day (MMcf/d) in the second quarter, down 11% from 507 MMcf/d in the same period in 2014.
- Cenovus anticipates continued declines in its natural gas production in future quarters, as the company continues to direct the majority of its capital investment to its crude oil properties.
- The company invested $2 million in these assets, compared with $5 million in the same quarter a year earlier.
- Cenovus's average realized sales price for natural gas, including hedging, was $3.21 per thousand cubic feet (Mcf), compared with $4.85/Mcf a year earlier.
- Natural gas use at Cenovus's operations is forecast to be about 180 MMcf/d in 2015.

Downstream

To capture the highest value for its oil, Cenovus takes an integrated approach to production, transportation, marketing and refining. The company is focused on finding new customers in North America and around the world where it expects to receive the best prices, and on ensuring it has the ability to move oil to those customers. Cenovus is also working to create a variety of oil blends that it expects will help maximize its transportation and refining options.

Cenovus has ownership in the Wood River Refinery in Illinois and the Borger Refinery in Texas. These refineries, which are jointly-owned with the operator, Phillips 66, produce high-quality end products like diesel, gasoline and jet fuel. On an integrated basis, Cenovus's refining business provides an economic hedge against heavy crude oil discounts to West Texas Intermediate (WTI).

The company continues to support proposed pipelines to Canada's east and west coasts as well as to the U.S. to help secure additional shipping capacity for its expected production growth. To complement this approach and access markets not served by pipeline, the company has also been pursuing a strategy to expand its capacity to transport oil by rail.

Refining and marketing

Operations

- Cenovus's refineries processed an average of 441,000 bbls/d gross of crude oil in the second quarter (96% utilization), down 5% from 466,000 bbls/d gross (101% utilization) in the same period a year ago. The decrease was largely the result of unplanned outages. Together, the two refineries processed an average of 200,000 bbls/d gross of heavy oil in the quarter, compared with 221,000 bbls/d gross in the second quarter of 2014.
- The refineries produced an average of 462,000 bbls/d gross of refined products in the second quarter, down 6% from 489,000 bbls/d gross in the same quarter in 2014.

Financial

- Operating cash flow from refining and marketing was $300 million in the second quarter, 36% higher than in the same period in 2014. The increase was primarily due to improved margins on the sale of secondary products such as coke and asphalt, the weakening of the Canadian dollar relative to the U.S. dollar and an increase in average market crack spreads.
- Higher operating cash flow was partially offset by the increase in heavy crude oil feedstock costs for Cenovus's refineries, relative to WTI, as the differential between the price of Canadian heavy oil and the price of benchmark light crude oil narrowed. The overall decrease in refined product output also had a negative impact on operating cash flow.
- Cenovus's refining operating cash flow is calculated on a first-in, first-out (FIFO) inventory accounting basis. Using the last-in, first-out (LIFO) accounting method employed by most U.S. refiners, Cenovus's operating cash flow from refining would have been $101 million lower in the second quarter, compared with $31 million lower in the second quarter of 2014.

- Capital investment was $48 million in the second quarter, compared with $46 million a year earlier. As a result of cost savings initiatives, 2015 capital spending is expected to be lower than originally anticipated, which is reflected in Cenovus's updated guidance.

Market access

- On average, Cenovus transported approximately 6,000 gross bbls/d of crude oil by rail in the second quarter to markets in Canada and the U.S., including eight unit train shipments.
- As part of its strategy to create a portfolio of transportation options designed to maximize market access and capture global prices for its oil, Cenovus agreed in June to purchase Canexus Corporation's rail trans-loading terminal at Bruderheim, Alberta for approximately $75 million, subject to closing adjustments. The transaction is expected to close August 31, 2015, subject to certain conditions. The terminal adds strategic value for Cenovus due to its existing pipeline connections to both the Cold Lake and Access crude oil pipeline systems as well as its links to the Canadian Pacific and Canadian National rail lines. Cenovus currently transports production volumes from Foster Creek to Bruderheim on the Cold Lake pipeline.
- Cenovus has 50,000 bbls/d of contracted capacity on Enbridge's Flanagan South system, increasing to 75,000 bbls/d in 2018. Initial deliveries on Flanagan South, which provides additional pipeline access to the U.S. Gulf Coast, began in December 2014.
- The company has firm service capacity of 11,500 bbls/d on the existing Trans Mountain pipeline, giving the company access to the West Coast.
- Cenovus has also committed to moving 200,000 bbls/d on TransCanada's proposed Energy East pipeline, has additional shipping capacity of 175,000 bbls/d on planned pipelines to the West Coast and has 75,000 bbls/d of committed capacity on TransCanada's proposed Keystone XL system.

Financial

Cash flow, earnings, capital investment, G&A and debt ratios

- Cenovus generated $477 million in cash flow in the second quarter, 60% less than in the same quarter a year prior. The decrease was due, in part, to the sharp year-over-year decline in crude oil and natural gas prices.
- Cash flow was also negatively impacted by higher than planned current income tax expense of $315 million, compared with a tax recovery of $7 million in the same period of 2014. The higher tax expense was primarily due to the acceleration in timing of income tax payable in response to the recent increase in the Alberta corporate income tax rate from 10% to 12%, effective July 1, 2015.
- Operating cash flow was $928 million in the second quarter, 28% lower compared with the second quarter of 2014.
- The company had operating cash flow, net of capital expenditures, of $67 million from crude oil production at its oil sands projects. Operating cash flow in excess of capital invested was $187 million from conventional oil, $76 million from natural gas and $252 million from refining and marketing.
- Cenovus had operating earnings of $151 million in the second quarter, compared with operating earnings of $473 million in the same quarter in 2014. The decrease was

primarily due to the decline in cash flow as well as an exploration expense of $21 million in the second quarter of 2015, compared with an exploration expense of $1 million in the same period of 2014. The decrease in operating earnings was partially offset by a recovery of deferred income tax and lower employee long-term incentive costs.

- Cenovus had net earnings of $126 million for the quarter, compared with net earnings of $615 million in the second quarter of 2014. In addition to lower operating earnings, the decline was related to higher unrealized risk management losses of $151 million, compared with $11 million in losses a year prior, and lower non-operating unrealized foreign exchange gains of $99 million, compared with $177 million in gains in the previous year's period. Net earnings were also impacted by a deferred income tax recovery of $261 million, compared with a deferred tax expense of $216 million in the second quarter of 2014.
- Capital investment was $357 million in the second quarter, a 48% decline from $686 million in the second quarter of 2014, as the company reduced capital spending to conserve cash. Almost three-quarters of the investment was at the company's oil sands operations, as it progressed expansion phases at Christina Lake and Foster Creek.
- G&A expenses were $73 million, 28% lower than in the second quarter of 2014. The decrease was primarily due to lower employee long-term incentive costs. Reductions in discretionary spending and workforce also contributed to the year-over-year improvement in G&A expenses.
- Over the long term, Cenovus continues to target a debt to capitalization ratio of between 30% and 40% and a debt to adjusted EBITDA ratio of between 1.0 and 2.0 times. At June 30, 2015, the company's debt to capitalization ratio was 35% and debt to adjusted EBITDA was 2.1 times, on a trailing 12-month basis. The net debt to capitalization ratio was 28% and net debt to adjusted EBITDA was 1.5 times, on a trailing 12-month basis. On a pro forma basis, including the proceeds from the sale of its royalty and fee land business, Cenovus would have had a second quarter net debt to capitalization ratio of 7%, with EBITDA of 0.3 times.

Commodity price hedging

- In the second quarter, Cenovus added Brent fixed-price hedges for July to September of 7,000 bbls/d at an average price of US$61.41/bbl and 25,000 bbls/d at an average price of C$80.76/bbl. In addition, Cenovus added Brent fixed-price hedges for October to December of 17,000 bbls/d at an average price of US$67.41/bbl and 8,000 bbls/d at an average price of C$82.59/bbl.
- For the first half of 2016, Cenovus added Brent fixed-price contracts of 9,000 bbls/d at an average price of US$69.63/bbl and 6,000 bbls/d at an average price of C$84.44/bbl. For the full-year 2016, Cenovus added Brent fixed-price hedges of 6,000 bbls/d at an average price of US$67.71/bbl.
- Cenovus had a realized after-tax hedging gain of $32 million in the second quarter, as the company's contract prices exceeded the average benchmark price. The company had unrealized after-tax hedging losses of $106 million in the quarter, primarily due to the realization of settled positions and increases in forward market prices.
- Cenovus received an average realized price, including hedging, of $51.23/bbl for its oil in the second quarter. This compares to an average realized price, including hedging, of $78.39/bbl in the second quarter of 2014. The average realized price for natural gas, including hedging, was $3.21/Mcf, compared with $4.85/Mcf a year ago.

Operating earnings[1]		
(For the period ended June 30) ($ millions, except per share amounts)	**2015** **Q2**	2014 Q2
Earnings (loss) before income tax Add back (deduct):	**180**	824
Unrealized risk management (gains) losses[2]	**151**	11
Non-operating unrealized foreign exchange (gains) losses[3]	**(99)**	(177)
(Gains) losses on divestiture of assets	**-**	(20)
Operating earnings (loss), before income tax	**232**	638
Income tax expense (recovery)	**81**	165
Operating earnings (loss)	**151**	473

[1] Operating earnings is a non-GAAP measure as defined in the Advisory.
[2] The unrealized risk management (gains) losses include the reversal of unrealized (gains) losses recognized in prior periods.
[3] Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.

Achievements and recognitions

Cenovus had its best safety performance ever during the first six months of 2015, with a total recordable injury frequency (TRIF) of 0.37, down 57% from the same period in 2014. In the second quarter, the TRIF was down 67% from the same period the previous year.

In June 2015, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the fourth year in a row. The company was also recognized by Corporate Knights magazine as one of the 2015 Best 50 Corporate Citizens in Canada for the fifth consecutive year. In addition, Cenovus was included in the Euronext Vigeo World 120 Index for the second year. The index recognizes the top 120 companies globally for their high degree of control of corporate responsibility risk and contributions to sustainable development. Cenovus released its 2014 corporate responsibility report in June, which can be found on cenovus.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated July 29, 2015, should be read in conjunction with our June 30, 2015 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2014 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2014 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of July 29, 2015, 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 its 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 sedar.com, EDGAR at 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, Net 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 listed on the Toronto and New York stock exchanges. On June 30, 2015, we had a market capitalization of approximately $17 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 for the six months ended June 30, 2015 was approximately 209,000 barrels per day and our average natural gas production was 456 MMcf per day. Our refineries processed an average of 440,000 gross barrels per day of crude oil feedstock into an average of 465,000 gross barrels per day of refined products.

The first half of 2015 continued to be challenging for the oil and gas industry. Average crude oil benchmark prices strengthened in the second quarter due to stronger global demand and slowing U.S. supply growth, but remained approximately 43 percent lower than in the second quarter of 2014. The decline in crude oil benchmark prices over the last twelve months has caused widespread reductions in capital spending programs and extensive efforts to reduce costs across the industry. Like all of our peers, Cenovus's share price has fallen, causing our market capitalization to drop approximately $9 billion since June 30, 2014. We continue to focus on preserving our financial resilience, exercising capital discipline and achieving sustainable cost reductions as we anticipate crude oil prices will remain low for a prolonged period of time.

Our Strategy

Our strategy is to create value by developing our vast oil sands resources and by achieving stronger global prices for our products. It is based on our execution excellence, our ability to innovate and our financial strength. The manufacturing approach we use to produce oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs, and improve productivity and efficiencies at every phase of our oil sands projects. We are focused on driving total shareholder returns through share price appreciation and a strong and sustainable dividend.

Our integrated approach enables us to capture the full value chain from production to high-quality end products like transportation fuels. It relies on:

- Our producing asset mix, including:
  - Oil sands for growth;
  - Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
  - 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.
- Our marketing, products and transportation activities, including:
  - Refining oil into various products to reduce the impact of commodity price fluctuations;
  - Creating a variety of oil blends to help maximize our transportation and refining options; and
  - Accessing new markets that will enable us to achieve the best pricing for our oil.

We plan to adopt a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies.

Oil Development

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek and Christina Lake. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta, including Narrows Lake, Telephone Lake and Grand Rapids, as well as our conventional oil opportunities. Our normal development planning is to evaluate these resources through stratigraphic test well drilling programs.

We anticipate increasing our annual net crude oil production, including our conventional crude oil operations, by fully developing our producing projects and those that currently have regulatory approval.

Execution Excellence

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, allowing us to minimize costs. 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. We are committed to developing our resources safely and responsibly.

Financial Strength

We anticipate our total annual capital investment for 2015 to be between $1.8 billion and $2.0 billion. This is a significant reduction from 2014 levels in response to the continued low commodity price environment. We expect proceeds from our common share issuance in March 2015, the sale of our royalty interest and mineral fee title lands business in July 2015 and internally generated cash flow to fund our capital investment in 2015 and into the next years of our business plan. We remain well positioned to manage through these volatile times. To continue to help ensure our financial flexibility, we plan to prudently use our balance sheet capacity, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

Dividend

In the first and second quarters of 2015, we paid dividends of $0.2662 per share. As we expect crude oil prices to remain low for a prolonged period of time and in anticipation of lower future cash flow due to the sale of our royalty interest and mineral fee title lands business, our Board reduced the third quarter dividend by 40 percent to $0.16 per share. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

In February 2015, we initiated a temporary three percent discount under our dividend reinvestment plan ("DRIP") for shareholders who reinvested their dividends in common shares. While the dividend reinvestment plan continues to be in place, the discount has been discontinued.

Innovation and the Environment

Technology development, research activities and understanding our impact on the environment play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technologies with the goal 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, building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Our Operations

Oil Sands

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

	Six Months Ended June 30, 2015		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	63,106	126,212
Christina Lake	50	74,410	148,820
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. Foster Creek and Christina Lake are producing and Narrows Lake is in the initial stages of development. These projects are located in the Athabasca region of northeastern Alberta. Two of our 100 percent-owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions, respectively.

	Six Months Ended June 30, 2015	
($ millions)	Crude Oil	Natural Gas
Operating Cash Flow	527	4
Capital Investment	673	1
Operating Cash Flow Net of Related Capital Investment	**(146)**	**3**

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flows. 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, 2015	
($ millions)	Crude Oil [1]	Natural Gas
Operating Cash Flow	387	155
Capital Investment	96	6
Operating Cash Flow Net of Related Capital Investment	**291**	**149**

(1) Includes NGLs.

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

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.

	Six Months Ended June 30, 2015	
	Ownership Interest (percent)	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 regional North American crude oil differential fluctuations. 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, 2015
Operating Cash Flow	395
Capital Investment	92
Operating Cash Flow Net of Related Capital Investment	**303**

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

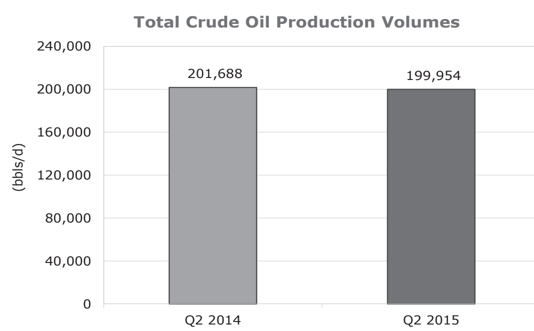
Challenges from the low commodity price environment continued to significantly impact our industry in the second quarter of 2015. Although average crude oil benchmark prices strengthened in the second quarter due to stronger global demand and slower U.S. supply growth, prices remained approximately 43 percent lower than in the second quarter of 2014. Forward commodity prices have declined since June 30, 2015 and are expected to be low for the remainder of 2015 with the forward price of Western Canadian Select ("WCS") as at July 24, 2015 expected to average approximately US$36 per barrel in the second half of 2015. Maintaining financial resilience, capital spending discipline and conserving cash are extremely important in this commodity price environment.

Cenovus remains well positioned to manage through these volatile times. We are focused on preserving our financial flexibility, exercising capital discipline, achieving sustainable cost reductions and maximizing shareholder value. In the second quarter, we:

- Reached an agreement to sell approximately 4.8 million gross acres of royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion. A royalty on Cenovus's working interest production on these fee lands and a Gross Overriding Royalty ("GORR") on production from our Pelican Lake and Weyburn assets were also included in the sale;
- Agreed to purchase a crude-by-rail trans-loading facility for $75 million, subject to closing adjustments, to expand our portfolio of transportation options;
- Reduced our total crude oil operating costs by $76 million or $4.29 per barrel to $12.48 per barrel compared with 2014;
- Reduced our discretionary spending across the Company;
- Renegotiated our $3.0 billion committed credit facility extending the maturity date to November 30, 2019 and added a new $1.0 billion tranche under the same facility with a maturity date of November 30, 2017; and
- Offered a temporary three percent discount under our DRIP for shareholders who reinvested their dividends in common shares. This resulted in cash savings of $96 million. While the dividend reinvestment plan continues to be in place, the discount has been discontinued.

Operational Results

Our upstream assets continued to perform well in the second quarter. Total crude oil production averaged 199,954 barrels per day in the quarter despite the shut-down of our Foster Creek operations for 11 full days due to a forest fire in northeastern Alberta.



Crude oil production from our Oil Sands segment averaged 130,734 barrels per day in the second quarter, an increase of five percent from the second quarter of 2014.

Production from Foster Creek averaged 58,363 barrels per day in the second quarter, an increase of three percent. Increases from the ramp-up of phase F and production from additional wells, including wells using our Wedge Well™ technology, were partially offset when production was shut down for 11 full days as a safety precaution due to a nearby forest fire.

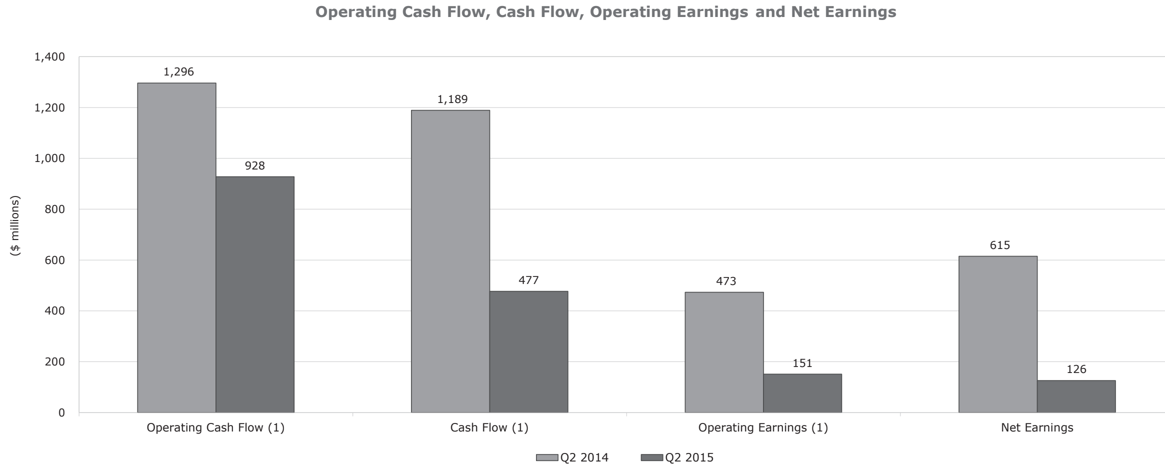
Average production at Christina Lake rose to 72,371 barrels per day, a six percent increase from the second quarter of 2014. The increase was due to production from additional wells, including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014, partially offset by operational outages due to electrical issues.

Our Conventional crude oil production averaged 69,220 barrels per day, a 10 percent decrease due to expected natural declines and the divestiture of a non-core asset in 2014, which produced 2,964 barrels per day in the second quarter of 2014.

Crude oil processed and refined product output decreased five percent and six percent, respectively, from 2014 due to unplanned outages. We processed an average of 441,000 gross barrels per day (2014 – 466,000 gross barrels per day) of crude oil, of which 200,000 gross barrels per day (2014 – 221,000 gross barrels per day) was heavy crude oil. We produced 462,000 gross barrels per day of refined products, a decrease of six percent.

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 2014 annual MD&A.



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

While crude oil benchmark prices improved from the first quarter of 2015, they were approximately 43 percent lower than in the second quarter of 2014. Low commodity prices continue to significantly impact our financial results.

Financial highlights for the second quarter of 2015 compared with 2014 include:

Operating Cash Flow

Operating Cash Flow decreased 28 percent to $928 million. Upstream Operating Cash Flow of $628 million (2014 – $1,076 million) declined primarily due to the low commodity price environment with our crude oil and natural gas sales prices declining by 39 percent and 42 percent, respectively.

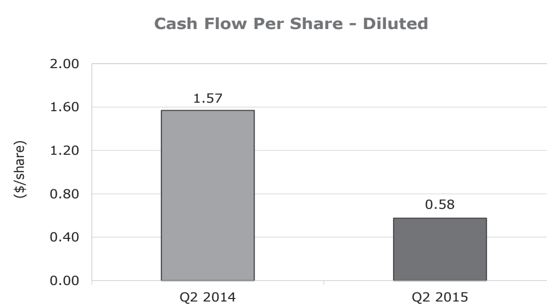
The decrease in upstream Operating Cash Flow due to lower commodity prices was partially offset by:

- Realized risk management gains of $47 million compared with losses of $55 million in 2014;
- Lower royalties primarily due to a decline in crude oil sales prices; and
- A reduction in crude oil operating expenses of $4.29 per barrel to $12.48 per barrel, primarily related to a decline in workover activities, lower fuel costs due to a decrease in natural gas prices, and lower repairs and maintenance costs.

Operating Cash Flow from our Refining and Marketing segment rose $80 million or 36 percent. The increase was due to improved margins on the sale of secondary products such as coke and asphalt, weakening of the Canadian dollar relative to the U.S. dollar, and an increase in average market crack spreads, partially offset by higher heavy crude oil feedstock costs relative to the West Texas Intermediate ("WTI") benchmark price and a six percent decrease in refined product output.

Cash Flow

Cash Flow decreased 60 percent to $477 million. Cash Flow was lower primarily due to the decline in Operating Cash Flow discussed above, and higher current income tax due to the acceleration in timing of income tax payable in response to the Alberta corporate tax rate increase.



Operating Earnings

Operating Earnings decreased $322 million to $151 million primarily due to a decrease in Cash Flow as discussed above and higher exploration expense compared with 2014. These decreases were partially offset by a recovery of deferred income tax compared with an expense in 2014 and lower employee long-term incentive costs.

Net Earnings

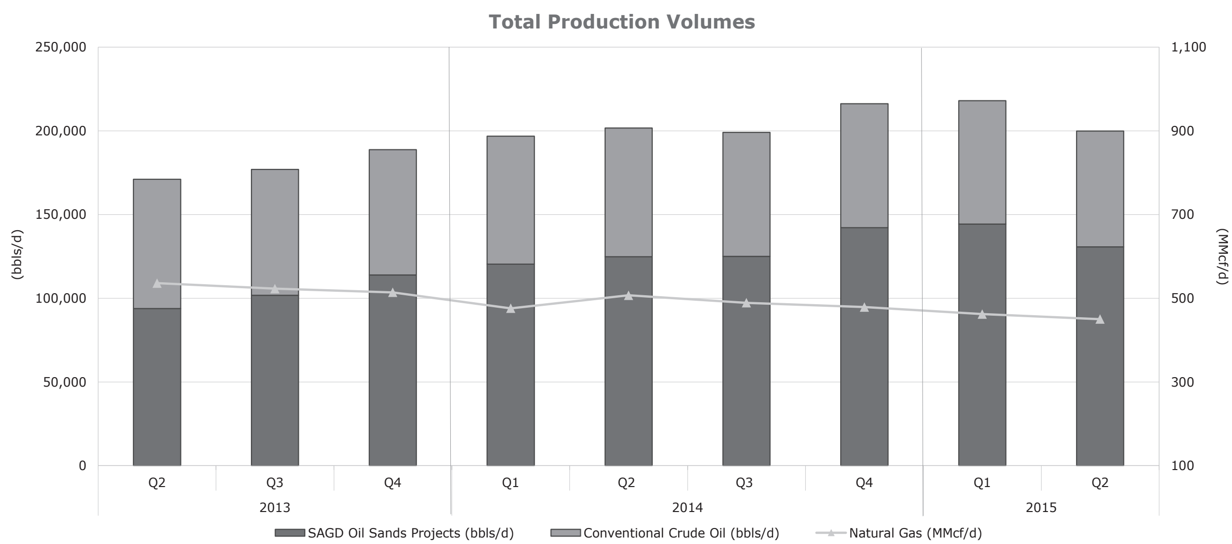
Net Earnings were $126 million in the quarter compared with $615 million in 2014. The decrease was primarily related to lower Operating Earnings as discussed above, larger unrealized risk management losses and a decrease in non-operating unrealized foreign exchange gains compared with 2014, partially offset by a deferred tax recovery.

Capital Investment

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the commodity price environment, focusing on capital discipline and conservation of cash. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges ahead.

Capital investment in the quarter was $357 million, a decrease of 48 percent. We continued to focus on sustaining existing oil sands production and completing the Foster Creek phase G expansion and Christina Lake's phase F expansion and optimization.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	Three Months Ended June 30, 2015	Percent Change	2014	Six Months Ended June 30, 2015	Percent Change	2014
Oil Sands						
Foster Creek	**58,363**	**3%**	56,852	**63,106**	**13%**	55,785
Christina Lake	**72,371**	**6%**	67,975	**74,410**	**11%**	66,863
	130,734	**5%**	124,827	**137,516**	**12%**	122,648
Conventional						
Heavy Oil	**36,099**	**(10)%**	40,304	**36,624**	**(10)%**	40,550
Light and Medium Oil	**31,809**	**(10)%**	35,329	**33,463**	**(4)%**	34,966
NGLs [(1)]	**1,312**	**7%**	1,228	**1,335**	**19%**	1,121
	69,220	**(10)%**	76,861	**71,422**	**(7)%**	76,637
Total Crude Oil Production	**199,954**	**(1)%**	201,688	**208,938**	**5%**	199,285

(1) NGLs include condensate volumes.

Foster Creek production increased in the three and six months ended June 30, 2015, primarily due to the ramp-up of phase F and production from additional wells, including wells using our Wedge Well™ technology. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately eighteen months from start-up, which occurred in the third quarter of 2014. Production increases were partially offset when production at Foster Creek was shut down for 11 full days as a safety precaution due to a nearby forest fire. There was no damage to our facilities. Lost production has been estimated at approximately 10,500 barrels per day, net, for the quarter. Stronger initial production following the start-up of operations has partially offset the lost production.

Production from Christina Lake increased in the second quarter and on a year-to-date basis due to production from additional wells, including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014. In addition, production was impacted by operational outages due to electrical issues in the second quarter of 2015.

Our Conventional crude oil production decreased during the three and six months ended June 30, 2015, due to expected natural declines and the divestitures of non-core assets in 2014.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Conventional	**429**	484	**436**	471
Oil Sands	**21**	23	**20**	21
	450	507	**456**	492

In the three and six months ended June 30, 2015, our natural gas production declined 11 percent and seven percent, respectively, as expected. We continue to direct the majority of our capital investment to our crude oil properties.

Operating Netbacks

	Three Months Ended June 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)		Six Months Ended June 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Price [2]	**49.48**	81.33	**2.82**	4.87	**39.90**	77.29	**2.94**	4.68
Royalties	**2.86**	7.41	**0.03**	0.09	**1.97**	6.59	**0.04**	0.08
Transportation and Blending [2]	**5.24**	3.20	**0.10**	0.11	**5.27**	2.90	**0.11**	0.11
Operating Expenses	**12.48**	16.77	**1.15**	1.23	**12.66**	17.36	**1.20**	1.24
Production and Mineral Taxes	**0.33**	0.60	**0.02**	0.13	**0.27**	0.51	**0.01**	0.06
Netback Excluding Realized Risk Management	**28.57**	53.35	**1.52**	3.31	**19.73**	49.93	**1.58**	3.19
Realized Risk Management Gain (Loss)	**1.75**	(2.94)	**0.39**	(0.02)	**4.27**	(2.48)	**0.34**	(0.01)
Netback Including Realized Risk Management	**30.32**	50.41	**1.91**	3.29	**24.00**	47.45	**1.92**	3.18

(1) Includes NGLs.

(2) The crude 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 was $22.58 per barrel for the second quarter (2014 – $32.94 per barrel) and in the six months ended June 30, 2015 was $22.43 per barrel (2014 – $33.73 per barrel).

Our average crude oil netback in the three and six months ended June 30, 2015, excluding realized risk management gains and losses, decreased $24.78 per barrel and $30.20 per barrel, respectively, compared with 2014. The declines primarily resulted from lower sales prices, consistent with the decline in benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar, lower operating costs and a decline in royalties. The weakening of the Canadian dollar, on a year-to-date basis, compared with 2014 had a positive impact on our crude oil price of approximately $4.46 per barrel.

In 2015, our average natural gas netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices consistent with the decline in the AECO benchmark price.

Refining [1]

	Three Months Ended June 30, 2015	Percent Change	2014	Six Months Ended June 30, 2015	Percent Change	2014
Crude Oil Runs (Mbbls/d)	**441**	**(5)%**	466	**440**	**2%**	433
Heavy Crude Oil	**200**	**(10)%**	221	**210**	**1%**	208
Refined Product (Mbbls/d)	**462**	**(6)%**	489	**465**	**2%**	458
Crude Utilization (percent)	**96**	**(5)%**	101	**96**	**2%**	94

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

In the second quarter, crude utilization decreased due to unplanned outages at our Borger refinery as a result of process unit outages and a power interruption.

On a year-to-date basis, crude oil runs and refined product output increased slightly. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at Borger compared with planned maintenance and turnarounds at both of our refineries in the first half of 2014. Utilization in the third quarter is anticipated to decline due to unplanned outages at our Borger refinery in July.

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 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,					
	2015	Percent Change	2014	Q2 2015	Q1 2015	Q2 2014
Crude Oil Prices (US$/bbl)						
Brent						
Average	59.33	(45)%	108.83	63.50	55.17	109.77
End of Period	63.59	(43)%	112.36	63.59	55.11	112.36
WTI						
Average	53.29	(47)%	100.84	57.94	48.63	102.99
End of Period	59.47	(44)%	105.37	59.47	47.60	105.37
Average Differential Brent-WTI	6.04	(24)%	7.99	5.56	6.54	6.78
WCS (2)						
Average	40.13	(49)%	79.25	46.35	33.90	82.95
End of Period	48.14	(42)%	83.18	48.14	37.30	83.18
Average Differential WTI-WCS	13.16	(39)%	21.59	11.59	14.73	20.04
Condensate (C5 @ Edmonton)						
Average	51.78	(50)%	103.90	57.94	45.62	105.15
Average Differential WTI-Condensate (Premium)/Discount	1.51	(149)%	(3.06)	-	3.01	(2.16)
Average Differential WCS-Condensate (Premium)/Discount	(11.65)	(53)%	(24.65)	(11.59)	(11.72)	(22.20)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	71.21	(39)%	117.51	79.96	62.45	121.98
Chicago Ultra-low Sulphur Diesel ("ULSD")	73.12	(42)%	125.09	75.92	70.33	124.34
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)						
Chicago	18.65	(3)%	19.13	20.77	16.53	19.72
Group 3	18.40	5%	17.58	19.34	17.46	17.75
Average Natural Gas Prices						
AECO (C$/Mcf)	2.81	(40)%	4.72	2.67	2.95	4.67
NYMEX (US$/Mcf)	2.81	(41)%	4.80	2.64	2.98	4.67
Basis Differential NYMEX-AECO (US$/Mcf)	0.53	6%	0.50	0.50	0.57	0.40
Foreign Exchange Rates (US$ per C$1)						
Average	0.810	(11)%	0.912	0.813	0.806	0.917

(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 average Canadian dollar WCS benchmark price for the second quarter was $57.01 per barrel (2014 – $90.46 per barrel) and for the six months ended June 30, 2015 was $49.54 per barrel (2014 – $86.90 per barrel).

Crude Oil Benchmarks

Crude oil benchmark prices improved in the second quarter of 2015 compared with the first quarter, but remained significantly lower than in 2014. The average Brent, WTI and WCS benchmark prices continued to be impacted by global imbalance of supply and demand which began in the last half of 2014. This global imbalance was created by weak global demand and strong growth in North American crude oil supply which was further amplified by the sustained decision of the Organization of Petroleum Exporting Countries ("OPEC") to maintain its level of crude oil output and discontinue its role as the swing supplier of crude oil. Despite significantly lower crude oil prices in 2015, the global imbalance has only slightly improved. However, crude oil benchmark prices showed some improvement in the second quarter of 2015 due to recovering European crude oil demand, stronger global gasoline demand, falling Mexican production and slowing U.S. supply growth.

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. In the three and six months ended June 30, 2015, the average price of Brent crude oil decreased 42 percent and 45 percent, respectively, compared with 2014. The decline was due to the global supply and demand imbalance discussed above.

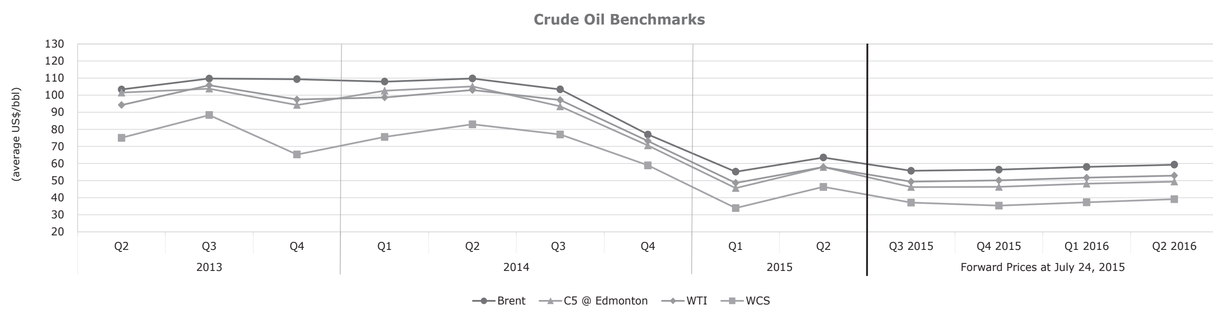
WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed by 18 percent in the second quarter compared with 2014 and by 24 percent on a year-to-date basis. WTI benchmark prices strengthened relative to Brent as a result of improved supply and demand balance in the U.S. Gulf Coast market, leaving transportation costs as the primary driver of the Brent-WTI differential.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed by US$8.45 per barrel (42 percent) in the second quarter of 2015 and narrowed by US$8.43 per barrel (39 percent) on a year-to-date basis. The narrowing of the differential was driven by increased demand for WCS due to new pipeline infrastructure to the U.S. Gulf Coast, growing rail capacity providing access to new and existing U.S. heavy oil refining markets, and reduced heavy crude oil supply caused by forest fires in northeastern Alberta during the second quarter of 2015.

Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. 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. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton.

In the second quarter of 2015, the average WTI-Condensate differential decreased by US$2.16 per barrel resulting from lower demand for condensate as forest fires in northeastern Alberta reduced oil sands production. On a year-to-date basis, the differential changed by US$4.57 per barrel, with condensate being sold at a discount to WTI in 2015 as compared with being sold at a premium in 2014. This change was primarily due to new diluent pipeline infrastructure into Alberta, condensate supply growth and lower oil sands production reducing condensate demand.

The average WCS-Condensate differential narrowed by US$10.61 per barrel in the second quarter and US$13.00 per barrel for the first half of the year compared with the respective 2014 period due to condensate supply growth as well as improved diluent transportation infrastructure for condensate imports into Alberta and heavy oil exports to market.



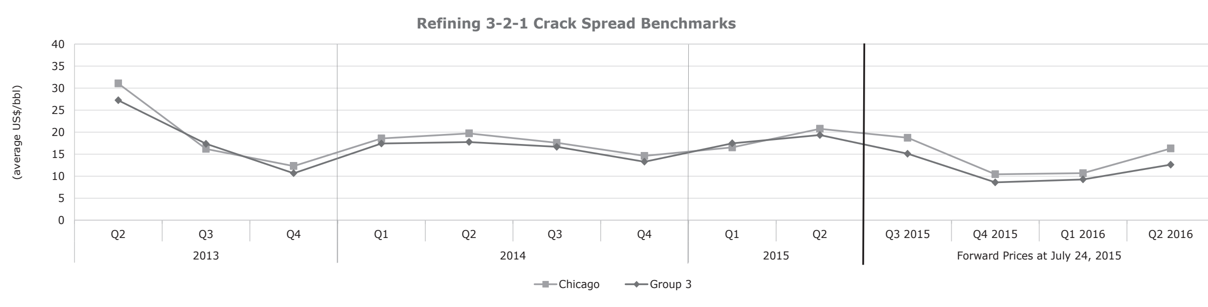
Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("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 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 decreased by 37 percent in the second quarter as compared with 2014 and by 41 percent on a year-to-date basis due to weaker global crude oil pricing.

Average Chicago 3-2-1 crack spreads increased by five percent in the second quarter compared with 2014 due to stronger global demand for gasoline as a result of weaker pricing. On a year-to-date basis, Chicago 3-2-1 crack spreads decreased slightly driven by the narrowing of the Brent-WTI differential as a result of new pipeline capacity to the U.S. Gulf Coast. Average Group 3 crack spreads increased in the second quarter and on a year-to-date basis as unplanned refinery outages resulted in slightly improved refined product pricing.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.



Natural Gas Benchmarks

Average natural gas prices decreased in the second quarter of 2015 and on a year-to-date basis primarily due to an increase in supply from the U.S. and Canada.

Foreign Exchange Benchmarks

Revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

In the second quarter and on a year-to-date basis compared with 2014, the Canadian dollar weakened by $0.10 or 11 percent relative to the U.S. dollar due to lower commodity prices and the strengthening of the U.S. economy. The weakening of the Canadian dollar for the six months ended June 30, 2015 compared with 2014, had a positive impact of approximately $767 million on our revenues and also resulted in an increase of $396 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

($ millions, except per share amounts)	Six Months Ended June 30, 2015	2014	2015 Q2	Q1	2014 Q4	Q3	Q2	Q1	2013 Q4	Q3	Q2
Revenues	**6,867**	10,434	**3,726**	3,141	4,238	4,970	5,422	5,012	4,747	5,075	4,516
Operating Cash Flow [1]	**1,477**	2,465	**928**	549	539	1,154	1,296	1,169	976	1,153	1,125
Cash Flow [1]	**972**	2,093	**477**	495	401	985	1,189	904	835	932	871
Per Share – Diluted	**1.21**	2.76	**0.58**	0.64	0.53	1.30	1.57	1.19	1.10	1.23	1.15
Operating Earnings (Loss) [1]	**63**	851	**151**	(88)	(590)	372	473	378	212	313	255
Per Share – Diluted	**0.08**	1.12	**0.18**	(0.11)	(0.78)	0.49	0.62	0.50	0.28	0.41	0.34
Net Earnings (Loss)	**(542)**	862	**126**	(668)	(472)	354	615	247	(58)	370	179
Per Share – Basic	**(0.67)**	1.14	**0.15**	(0.86)	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24
Per Share – Diluted	**(0.67)**	1.14	**0.15**	(0.86)	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24
Capital Investment [2]	**886**	1,515	**357**	529	786	750	686	829	898	743	706
Dividends											
Cash Dividends	**263**	403	**125**	138	201	201	201	202	183	182	183
In Shares from Treasury	**182**	-	**98**	84	-	-	-	-	-	-	-
Per Share	**0.5324**	0.5324	**0.2662**	0.2662	0.2662	0.2662	0.2662	0.2662	0.242	0.242	0.242

(1) Non-GAAP measure defined in this MD&A.
(2) Includes expenditures on PP&E and Exploration and Evaluation (“E&E”) assets.

Revenues

In the second quarter, revenues decreased $1,696 million (31 percent) compared with 2014. On a year-to-date basis, revenues decreased $3,567 million (34 percent) compared with 2014.

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2014	**5,422**	**10,434**
Increase (Decrease) due to:		
Oil Sands	**(426)**	**(906)**
Conventional	**(374)**	**(738)**
Refining and Marketing	**(1,046)**	**(2,208)**
Corporate and Eliminations	**150**	**285**
Revenues for the Periods Ended June 30, 2015	**3,726**	**6,867**

Upstream revenues declined in the second quarter and on a year-to-date basis by 37 percent and 40 percent, respectively, due to lower crude oil blend and natural gas sales prices, in line with the decrease in WCS and the AECO benchmark prices. Lower crude oil sales prices also decreased royalties. Upstream revenues on a year-to-date basis benefited from crude oil sales volumes increasing five percent.

Revenues generated by our Refining and Marketing segment in the three and six months ended June 30, 2015 decreased 30 percent and 33 percent, respectively. Refining revenues declined during the second quarter due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices, and a six percent decline in refined product output, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales undertaken by the marketing group decreased 30 percent compared with 2014, primarily due to a decline in crude oil and natural gas sales prices, partially offset by an increase in purchased crude oil volumes.

On a year-to-date basis, refining revenues decreased due to lower refined product benchmark pricing, partially offset by a slightly higher refined product output and weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales decreased 37 percent primarily due to a decline in crude oil and natural gas sales prices, partially offset by 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.

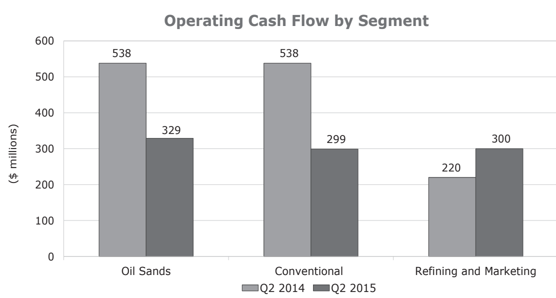
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

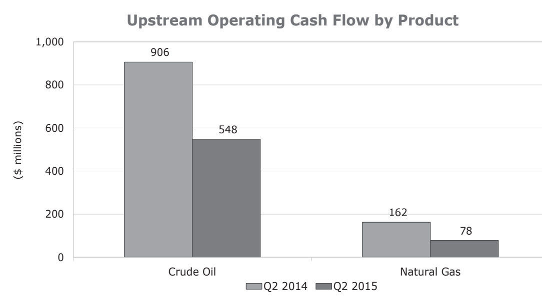
Operating Cash Flow

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 periods. 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Revenues	**3,794**	5,640	**7,041**	10,893
(Add) Deduct:				
Purchased Product	**1,976**	3,098	**3,814**	5,918
Transportation and Blending	**498**	655	**1,026**	1,308
Operating Expenses	**432**	519	**910**	1,093
Production and Mineral Taxes	**6**	17	**11**	24
Realized (Gain) Loss on Risk Management Activities	**(46)**	55	**(197)**	85
Operating Cash Flow	**928**	1,296	**1,477**	2,465

Three Months Ended June 30, 2015 Compared With June 30, 2014





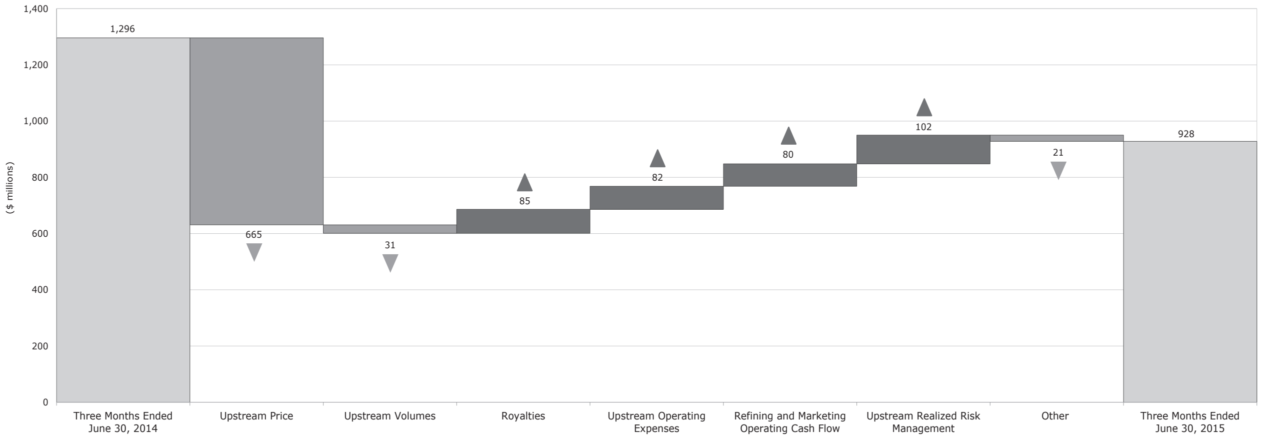
Operating Cash Flow declined 28 percent in the second quarter compared with 2014 primarily due to:

- A 39 percent decrease in our average crude oil sales price and a 42 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices; and
- An 11 percent decrease in our natural gas sales volumes.

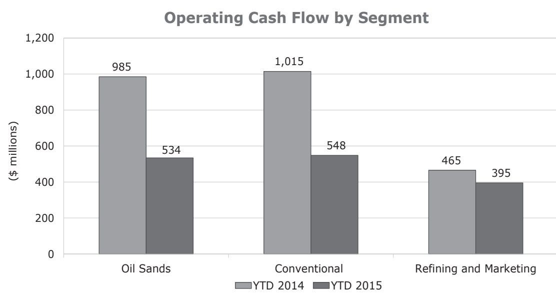
These declines to Operating Cash Flow were partially offset by:

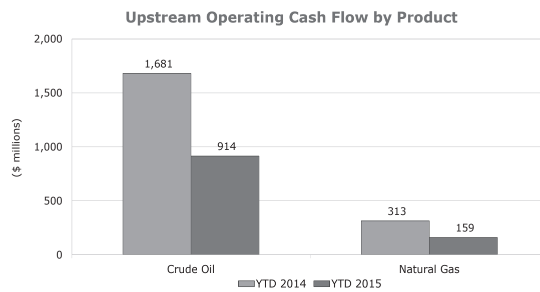
- Realized risk management gains of $47 million, excluding Refining and Marketing, compared with losses of $55 million in 2014;
- Lower royalties primarily due to a decline in crude oil sales prices;
- A reduction of $4.29 per barrel in crude oil operating expenses primarily related to a decline in workover activities, lower fuel costs due to a decrease in natural gas prices, and lower repairs and maintenance costs; and
- Higher Operating Cash Flow from Refining and Marketing as a result of improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar, and an increase in average market crack spreads. These increases were partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and a decrease in refined product output.

Operating Cash Flow Variance



Six Months Ended June 30, 2015 Compared With June 30, 2014





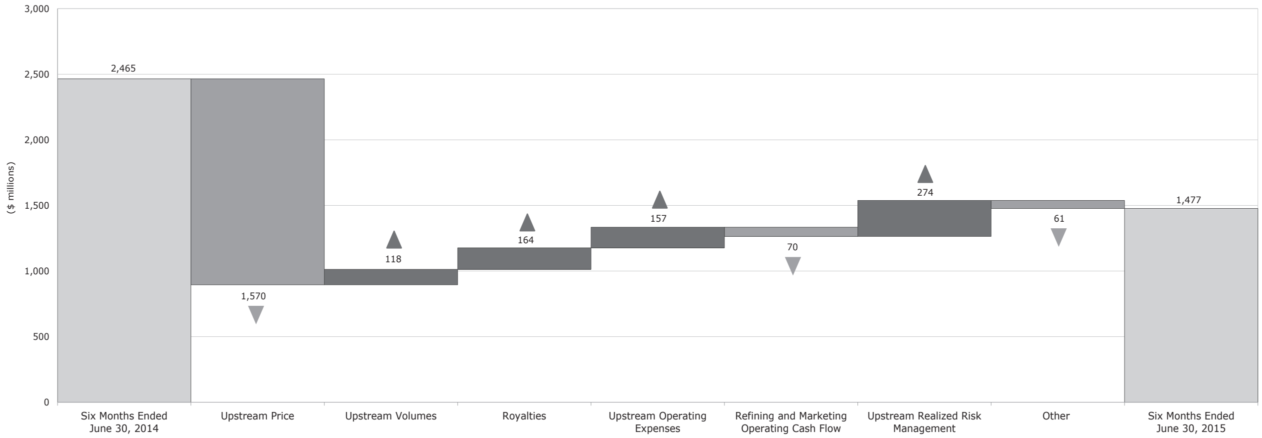
Operating Cash Flow declined 40 percent in the first six months of 2015 primarily due to:

- A 48 percent decrease in our average crude oil sales price and a 37 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- Lower Operating Cash Flow from Refining and Marketing as a result of higher heavy crude oil feedstock costs relative to the WTI benchmark price, partially offset by improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar, and a slight increase in refined product output; and
- A seven percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- Realized risk management gains of $184 million, excluding Refining and Marketing, compared with losses of $90 million in 2014;
- Lower royalties primarily due to a decrease in crude oil and natural gas sales prices;
- A five percent increase in our crude oil sales volumes; and
- A decrease of $4.70 per barrel in crude oil operating expenses primarily due to a decline in workover activities, a reduction in fuel costs due to lower natural gas prices, and lower repairs and maintenance costs.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Cash From Operating Activities	**335**	1,109	**610**	1,566
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(14)**	(27)	**(68)**	(69)
Net Change in Non-Cash Working Capital	**(128)**	(53)	**(294)**	(458)
Cash Flow	**477**	1,189	**972**	2,093

In the three and six months ended June 30, 2015, Cash Flow decreased $712 million and $1,121 million, respectively, predominantly due to lower Operating Cash Flow, as discussed above. Cash Flow was also impacted by higher current income tax, which increased $322 million and $161 million in the three and six months ended June 30, 2015, primarily due to the acceleration in timing of income tax payable in response to the Alberta corporate tax rate increase.

Operating Earnings (Loss)

Operating Earnings (Loss) 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 (Loss) is defined as Earnings (Loss) 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, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Earnings (Loss), Before Income Tax	**180**	824	**(601)**	1,182
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (1)	**151**	11	**296**	(15)
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**(99)**	(177)	**415**	19
(Gain) Loss on Divestiture of Assets	**-**	(20)	**(16)**	(20)
Operating Earnings, Before Income Tax	**232**	638	**94**	1,166
Income Tax Expense	**81**	165	**31**	315
Operating Earnings	**151**	473	**63**	851

(1) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(2) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.

Operating Earnings decreased $322 million in the second quarter of 2015, primarily due to:

- A decrease in Cash Flow as discussed above; and
- A higher exploration expense compared with 2014.

These decreases were partially offset by a recovery of deferred income tax, compared with an expense in 2014, and lower employee long-term incentive costs.

On a year-to-date basis, Operating Earnings decreased $788 million, primarily due to:

- A decrease in Cash Flow as discussed above;
- Unrealized foreign exchange losses of $6 million related to operating items, as compared with gains of $57 million in 2014; and
- An increase in DD&A primarily related to higher sales volumes from our oil sands assets.

These decreases were partially offset by a recovery of deferred income tax, compared with an expense in 2014, and a recovery of employee long-term incentive costs compared with an expense in 2014.

Net Earnings (Loss)

($ millions)	Three Months Ended	Six Months Ended
Net Earnings for the Periods Ended June 30, 2014	**615**	**862**
Increase (Decrease) due to:		
Operating Cash Flow (1)	**(368)**	**(988)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(140)**	**(311)**
Unrealized Foreign Exchange Gain (Loss)	**(79)**	**(459)**
Gain (Loss) on Divestiture of Assets	**(20)**	**(4)**
Expenses (2)	**(20)**	**41**
Depreciation, Depletion and Amortization	**3**	**(42)**
Exploration Expense	**(20)**	**(20)**
Income Tax Expense	**155**	**379**
Net Earnings (Loss) for the Periods Ended June 30, 2015	**126**	**(542)**

(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.

Net Earnings for the three and six months ended June 30, 2015 decreased $489 million and $1,404 million, respectively, primarily due to:

- A decline in Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange gains of $99 million in the quarter and unrealized losses of $415 million on a year-to-date basis (2014 – unrealized gains of $177 million and unrealized losses of $19 million, respectively); and
- Unrealized risk management losses of $151 million in the quarter and $296 million on a year-to-date basis compared with unrealized losses of $11 million in the second quarter of 2014 and unrealized gains of $15 million for the six months ended June 30, 2014.

These decreases were partially offset by lower income tax as a deferred income tax recovery offset higher current tax.

Net Capital Investment

($ millions)	Three Months Ended June 30, 2015	2014	Six Months Ended June 30, 2015	2014
Oil Sands	**260**	471	**674**	998
Conventional	**36**	153	**102**	423
Refining and Marketing	**48**	46	**92**	69
Corporate and Eliminations	**13**	16	**18**	25
Capital Investment	**357**	686	**886**	1,515
Acquisitions	**-**	16	**-**	17
Divestitures	**-**	(39)	**(16)**	(41)
Net Capital Investment (1)	**357**	663	**870**	1,491

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

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the commodity price environment, with a focus on capital discipline and conservation of cash. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges expected from an extended period of low commodity prices and market volatility.

Capital investment in the three and six months ended June 30, 2015 declined 48 percent and 42 percent, respectively. In January, we reduced our planned capital investment with the intent of conserving cash and maintaining the strength of our balance sheet in light of the low commodity price environment. We plan to focus 2015 capital investment on ensuring our assets are appropriately maintained, meet safety, regulatory and contractual obligations, and on our Christina Lake phase F and Foster Creek phase G expansions.

In 2015, Oil Sands capital investment focused primarily on sustaining capital related to existing production, phase G expansion at Foster Creek, Christina Lake's phase F expansion and the optimization project, and the drilling of 158 gross stratigraphic test wells in the first half of 2015, which were primarily related to near-term phase expansions to determine pad placement.

Conventional capital investment focused primarily on maintenance capital and spending for our CO_2 project at Weyburn.

Capital investment in the Refining and Marketing segment focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives.

Capital also includes spending on technology development, which plays an integral role in our business. Having a strategy focused on innovation and technology development 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, which was primarily for computer equipment.

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:

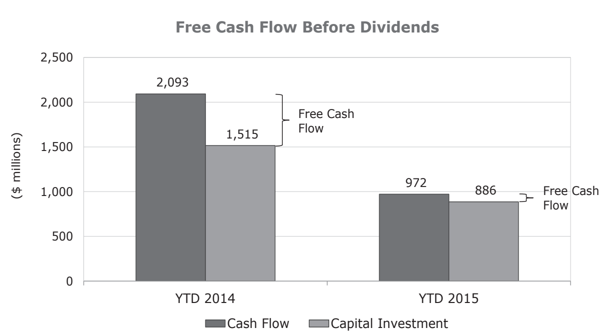
- First, to capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital.

Our approach to capital allocation 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. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. We anticipate maintaining investment grade credit ratings.

We anticipate our total annual capital investment for 2015 to be between $1.8 billion and $2.0 billion, significantly below prior years, in light of the commodity price environment. Our capital budget has a degree of flexibility and, as such, we will continue to assess spending plans on a regular basis and make adjustments, if required. Refer to the Reportable Segments section of this MD&A for more details.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Cash Flow [1]	**477**	1,189	**972**	2,093
Capital Investment (Committed and Growth)	**357**	686	**886**	1,515
Free Cash Flow [2]	**120**	503	**86**	578
Cash Dividends	**125**	201	**263**	403
	(5)	302	**(177)**	175

(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.



We expect our capital investment in 2015 and into the next years of our business plan to be funded from internally generated cash flow, proceeds from our common share issuance in March 2015 and the sale of our royalty interest and mineral fee title lands business in July 2015. These transactions strengthen our balance sheet and provide us with greater resiliency to consider investing in opportunities within Cenovus that we believe have strong future returns. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

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 Cenovus'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 responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. 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.

Revenues by Reportable Segment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Oil Sands	**875**	1,301	**1,604**	2,510
Conventional	**482**	856	**904**	1,642
Refining and Marketing	**2,437**	3,483	**4,533**	6,741
Corporate and Eliminations	**(68)**	(218)	**(174)**	(459)
	3,726	5,422	**6,867**	10,434

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 development, 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 developments in our Oil Sands segment in the second quarter of 2015 compared with 2014 include:

- A forest fire in northeastern Alberta caused operations to be shut down at Foster Creek for 11 full days as a safety precaution. There was no damage to our facilities. This reduced average production at Foster Creek by approximately 10,500 barrels per day, net; however, production losses were reduced by stronger initial production following the start-up of operations; and
- Christina Lake production increasing six percent, to an average of 72,371 barrels per day primarily due to production from additional wells, including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014, partially offset by operational outages due to electrical issues.

Oil Sands – Crude Oil

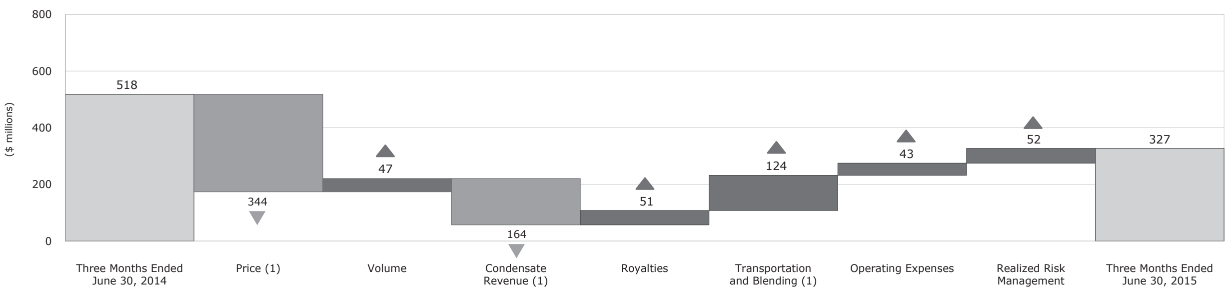
Three Months Ended June 30, 2015 Compared With June 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted)	Three Months Ended June 30, 2015	$ per-unit (1)	Three Months Ended June 30, 2014	$ per-unit (1)
Gross Sales	**884**	77	1,345	124
Less: Royalties	**16**	1	67	6
Revenues	**868**	76	1,278	118
Expenses				
Transportation and Blending	**435**	38	559	52
Operating	**123**	11	166	15
(Gain) Loss on Risk Management	**(17)**	(2)	35	3
Operating Cash Flow	**327**	29	518	48
Capital Investment	**260**		470	
Operating Cash Flow Net of Related Capital Investment	**67**		48	

(1) Per-unit amounts are calculated on an unblended crude oil basis.

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 $45.61 per barrel. While our average price has improved from the first quarter price of $26.04 per barrel, it was 40 percent lower than the second quarter of 2014. The prices we receive continue to be adversely impacted by the worldwide commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market that secure a higher sales price. The WCS-CDB differential narrowed by 54 percent to a discount of US$2.00 per barrel (2014 – a discount of US$4.33 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In the second quarter, 88 percent of our Christina Lake production was sold as CDB (2014 – 84 percent), with the remainder sold into the WCS stream.

Production Volumes

(barrels per day)	Three Months Ended June 30, 2015	Percent Change	2014
Foster Creek	**58,363**	**3%**	56,852
Christina Lake	**72,371**	**6%**	67,975
	130,734	**5%**	124,827

Foster Creek production increased primarily due to the ramp-up of phase F and production from additional wells, including wells using our Wedge Well™ technology. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately eighteen months from start-up, which occurred in the third quarter of 2014. Production increases were partially offset when operations at Foster Creek were shut down for 11 full days as a safety precaution due to a nearby forest fire. Lost production has been estimated at approximately 10,500 barrels per day, net, for the quarter. Stronger initial production following the start-up of operations partially offset the lost production.

Production from Christina Lake increased in the second quarter due to production from additional wells including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014. In addition, production was impacted by operational outages due to electrical issues.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate.

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 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). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs.

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.

Effective Royalty Rates

	Three Months Ended June 30,	
(percent)	**2015**	2014
Foster Creek	**5.0**	9.3
Christina Lake	**2.5**	7.7

Royalties decreased $51 million in the second quarter relative to the same period in 2014, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. Foster Creek royalties in both 2015 and 2014 were based on net profits. The royalty calculation was also based on net profits in the second quarter of 2014. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $124 million or 22 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes consistent with the rise in production. Our condensate costs were higher than the average benchmark price in 2015 primarily due to the utilization of higher priced inventory and the transportation cost associated with moving the condensate to our oil sands projects.

Transportation costs increased $40 million primarily due to higher pipeline tariffs and additional sales to the U.S. market which attract higher tariffs. To ensure adequate capacity for our expected future production growth, we hold long-term transportation agreements on the Cold Lake pipeline expansion. Deliveries commenced in the first quarter of 2015. We also have added capacity on the Flanagan South system that will increase our sales opportunities into the U.S. market which is expected to provide a higher sales price. Deliveries on the Flanagan South system began in the fourth quarter of 2014. Future production growth is expected to reduce our per-barrel transportation costs.

In addition, transportation costs increased as a result of higher volumes transported by rail. In the second quarter of 2015, we moved an average of 5,210 gross barrels per day of crude oil by rail, consisting of eight unit train shipments (2014 – 2,605 gross barrels per day, including four unit train shipments). Rail transportation costs are generally higher than pipeline costs; however, rail provides flexibility in destinations, products transported and the duration of the cost commitment, which is typically shorter in term than pipeline commitments.

Operating

Primary drivers of our operating expenses in the second quarter of 2015 were workforce, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses decreased $43 million or $4.64 per barrel, primarily as a result of a decline in workover activities, lower natural gas prices reducing fuel costs, and higher production.

Per-unit Operating Expenses

($/bbl)	Three Months Ended June 30, 2015	Percent Change	2014
Foster Creek			
Fuel	**2.78**	**(40)%**	4.60
Non-fuel	**10.69**	**(28)%**	14.78
Total	**13.47**	**(30)%**	19.38
Christina Lake			
Fuel	**2.18**	**(44)%**	3.86
Non-fuel	**6.14**	**(25)%**	8.22
Total	**8.32**	**(31)%**	12.08
Total	**10.74**	**(30)%**	15.38

At Foster Creek, fuel costs decreased $1.82 per barrel primarily due to the decline in natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined $4.09 per barrel, primarily due to:

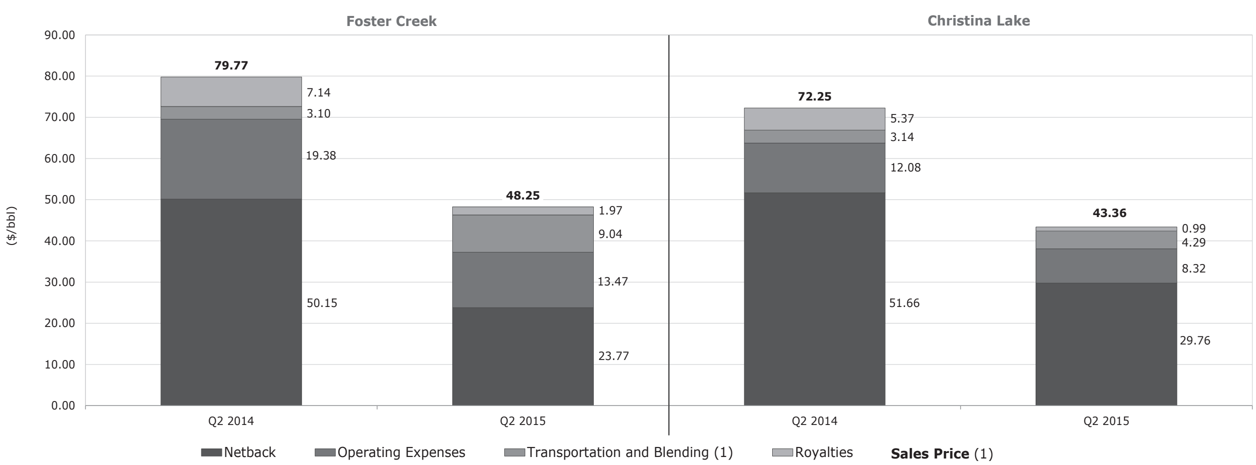
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes; and
- Higher production volumes.

Foster Creek non-fuel operating expenses included approximately $2.6 million or $0.49 per barrel of incremental costs associated with the shut-down due to the forest fire.

At Christina Lake, fuel costs decreased by $1.68 per barrel due to the decline in natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased $2.08 per barrel, primarily due to:

- A decrease in repairs and maintenance costs due to a focus on critical operational activities and incurring turnaround costs in 2014;
- Lower workover costs due to fewer pump changes; and
- Increased production.

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 $29.82 per barrel (2014 – $47.28 per barrel) for Foster Creek, and $32.90 per barrel (2014 – $49.30 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

Risk Management

Risk management activities in the second quarter resulted in realized gains of $17 million (2014 – realized losses of $35 million), consistent with our contract prices exceeding average benchmark prices.

Six Months Ended June 30, 2015 Compared With June 30, 2014

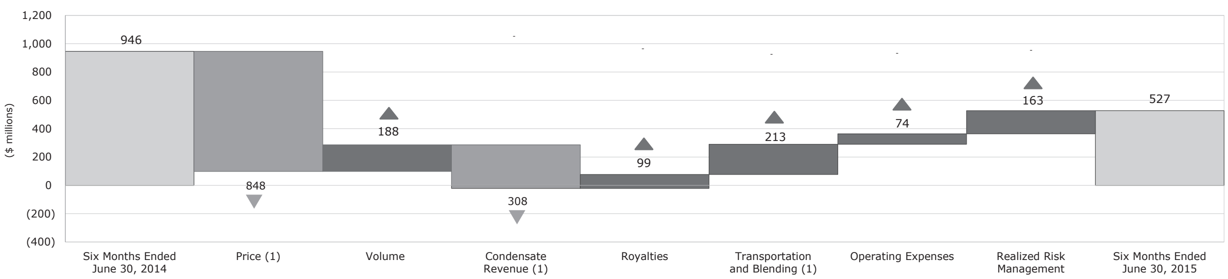
Financial and Per-unit Results

($ millions, unless otherwise noted)	Six Months Ended June 30, 2015	$ per-unit [1]	Six Months Ended June 30, 2014	$ per-unit [1]
Gross Sales	**1,607**	67	2,575	120
Less: Royalties	**19**	1	118	5
Revenues	**1,588**	66	2,457	115
Expenses				
Transportation and Blending	**905**	37	1,118	52
Operating	**262**	11	336	16
(Gain) Loss on Risk Management	**(106)**	(4)	57	3
Operating Cash Flow	**527**	22	946	44
Capital Investment	**673**		995	
Operating Cash Flow Net of Related Capital Investment	**(146)**		(49)	

(1) Per-unit amounts are calculated on an unblended crude oil basis.

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments, and proceeds from our common share issuance in the first quarter of 2015.

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, 2015, our average crude oil sales price was $35.35 per barrel, a 50 percent decrease from 2014 as the prices we received continue to be adversely impacted by the worldwide commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market which secure a higher sales price. The WCS-CDB differential narrowed by 51 percent to a discount of US$2.27 per barrel (2014 – a discount of US$4.61 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In the first half of 2015, 87 percent of our Christina Lake production was sold as CDB (2014 – 85 percent), with the remainder sold into the WCS stream.

Production Volumes

	Six Months Ended June 30,		
(barrels per day)	2015	Percent Change	2014
Foster Creek	**63,106**	**13%**	55,785
Christina Lake	**74,410**	**11%**	66,863
	137,516	**12%**	122,648

Foster Creek production increased due to production from phase F coming on stream in September 2014 and ramping up as expected, and production from additional wells, including wells using our Wedge Well™ technology, partially offset by the impact of a forest fire near our operations. The forest fire resulted in a decrease in production of approximately 5,300 barrels per day, net, in the first half of 2015. Stronger initial production following the start-up of operations partially offset the decrease due to the fire.

Production from Christina Lake increased in the six months ended June 30, 2015 due to production from additional wells including wells using our Wedge Well™ technology, improved performance of our facilities, and phase E reaching nameplate production capacity in the second quarter of 2014.

Royalties

Effective Royalty Rates

(percent)	Six Months Ended June 30, 2015	2014
Foster Creek	**2.8**	8.7
Christina Lake	**2.7**	7.4

Royalties decreased $99 million, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. At Foster Creek, this resulted in a royalty calculation based on net profits, which was consistent with the first half of 2014. In addition, in the first quarter of 2015 we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation and recorded an associated credit, decreasing the overall royalty rate in the first half of 2015. Excluding the credit, the effective royalty rate for Foster Creek would have been 5.0 percent. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $213 million or 19 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes consistent with the rise in production. Our condensate costs were higher than the average benchmark price in 2015 primarily due to the utilization of higher priced inventory and the transportation cost associated with moving the condensate to our oil sands projects.

Transportation costs increased $95 million primarily due to higher pipeline tariffs and additional sales to the U.S. market which attract higher tariffs. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

In addition, transportation costs increased as a result of higher volumes moved by rail. In the six months ended June 30, 2015, we transported an average of 8,522 gross barrels per day of crude oil by rail, consisting of 26 unit train shipments (2014 – 2,286 gross barrels per day, including seven unit train shipments).

Operating

Primary drivers of our operating expenses in the first half of 2015 were workforce, fuel, repairs and maintenance, and workovers. Total operating expenses decreased $74 million or $4.81 per barrel, primarily as a result of lower natural gas prices that reduced fuel costs, higher production and a decline in workover activities.

Per-unit Operating Expenses

($/bbl)	Six Months Ended June 30, 2015	Percent Change	2014
Foster Creek			
Fuel	**2.87**	**(43)%**	5.03
Non-fuel	**11.12**	**(22)%**	14.21
Total	**13.99**	**(27)%**	19.24
Christina Lake			
Fuel	**2.18**	**(50)%**	4.33
Non-fuel	**6.08**	**(27)%**	8.35
Total	**8.26**	**(35)%**	12.68
Total	**10.86**	**(31)%**	15.67

At Foster Creek, fuel costs decreased $2.16 per barrel primarily due to the decline in natural gas prices. Non-fuel operating expenses declined $3.09 per barrel, primarily due to:

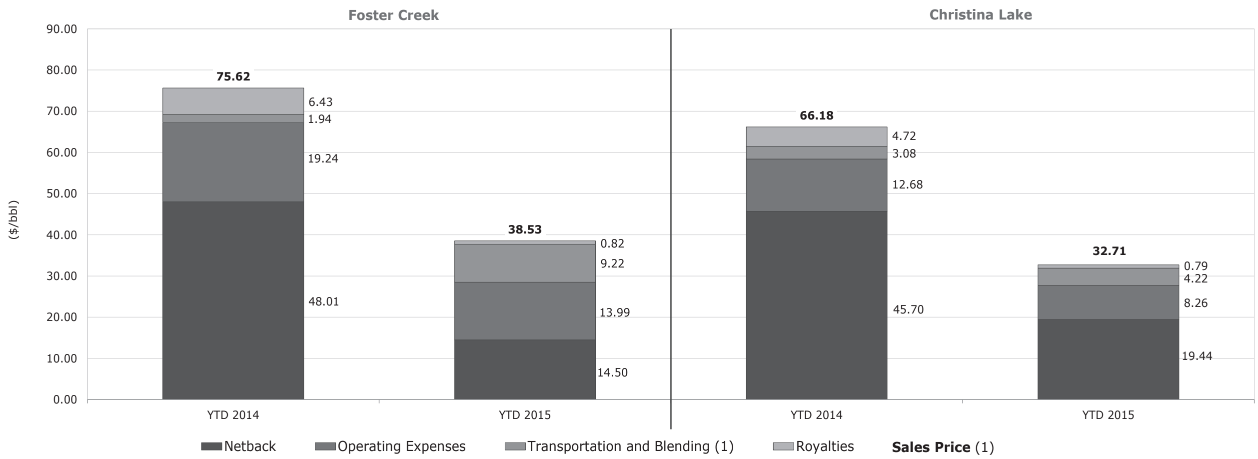
- Higher production volumes; and
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes.

Foster Creek non-fuel operating expenses included approximately $2.6 million or $0.24 per barrel of incremental costs associated with the shut-down due to the nearby forest fire in the second quarter of 2015.

At Christina Lake, fuel costs decreased by $2.15 per barrel due to the decline in natural gas prices and a decrease in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased $2.27 per barrel, primarily due to:

- Increased production;
- Lower workover costs due to fewer pump changes; and
- A decrease in repairs and maintenance costs due to a focus on critical operational 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, 2015 was $30.21 per barrel (2014 – $47.81 per barrel) for Foster Creek, and $32.21 per barrel (2014 – $51.02 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

Risk Management

Risk management activities in the first six months of 2015 resulted in realized gains of $106 million (2014 – realized losses of $57 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent-owned natural gas operations in Athabasca. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for the three and six months ended June 30, 2015, net of internal usage, was 21 MMcf per day and 20 MMcf per day, respectively (2014 – 23 MMcf per day and 21 MMcf per day, respectively). Although operations at Athabasca were shut down in the second quarter of 2015 as a precaution due to a nearby forest fire, natural gas production was not significantly impacted. Operating Cash Flow was $1 million in the second quarter (2014 – $15 million) and $4 million on a year-to-date basis (2014 – $38 million). These decreases were primarily related to the decline in natural gas sales prices.

Oil Sands – Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Foster Creek	**73**	209	**222**	430
Christina Lake	**161**	183	**368**	365
	234	392	**590**	795
Narrows Lake	**9**	45	**29**	92
Telephone Lake	**4**	19	**15**	71
Grand Rapids	**12**	5	**26**	16
Other (1)	**1**	10	**14**	24
Capital Investment (2)	**260**	471	**674**	998

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

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the commodity price environment, with a focus on capital discipline and conservation of cash. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges expected from an extended period of low commodity prices and market volatility. We plan to focus our 2015 capital investment on base business activities and on our oil sands expansion phases that are expected to generate near-term cash flow.

Existing Projects

Capital investment at Foster Creek on a year-to-date basis focused on sustaining capital related to existing production, expansion phase G and the drilling of stratigraphic test wells primarily related to future sustaining well pads. In the second quarter, capital investment declined compared with 2014 due to lower spending related to field construction and completion costs with the commissioning of phase F in 2014. On a year-to-date basis, capital investment decreased mainly due to lower spending on phase F construction.

In the first six months of 2015, Christina Lake capital investment focused on sustaining capital related to existing production, expansion phases F and G, and the optimization project. Capital investment in the second quarter decreased primarily due to lower spending on phase F facility detailed engineering and procurement. On a year-to-date basis, capital investment increased due to sustaining activities and advancing phase G engineering and procurement, offset by lower spending on phase F facilities.

Capital investment at Narrows Lake in 2015 focused on detailed engineering and procurement for phase A. Capital investment declined in the second quarter and on a year-to-date basis due to the suspension of new construction on phase A until further notice.

Emerging Projects

In the six months ended June 30, 2015, Telephone Lake capital investment was primarily focused on front-end engineering work on the central processing facility. Capital spending decreased in the second quarter and on a year-to-date basis as we did not drill any stratigraphic test wells in the first half of 2015 (2014 – 33 stratigraphic test wells).

Capital investment at Grand Rapids in 2015 has been primarily focused on continued operation at the SAGD pilot project. A third well pair was drilled, completed and commenced steam circulation. Capital investment increased compared with 2014 due to the dismantling, removal and storage of an existing SAGD facility purchased in 2014 and costs associated with the third well pair, partially offset by the lack of stratigraphic test wells drilled in 2015.

Drilling Activity (1)

	Gross Stratigraphic Test Wells (2)		Gross Production Wells (3) (4)	
Six Months Ended June 30,	**2015**	2014	**2015**	2014
Foster Creek	**122**	147	**10**	38
Christina Lake	**36**	52	**33**	35
	158	199	**43**	73
Narrows Lake	**-**	22	**-**	-
Telephone Lake	**-**	33	**-**	-
Grand Rapids	**-**	9	**1**	-
Other	**-**	21	**-**	-
	158	284	**44**	73

(1) In addition to the drilling activity included within the table, we drilled five gross service wells in the six months ended June 30, 2015 (2014 – one gross service well).
(2) 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, 2015, we drilled seven wells (2014 – two wells) and commissioned our second SkyStrat™ drilling rig.
(3) SAGD well pairs are counted as a single producing well.
(4) Includes wells drilled using our Wedge Well™ technology.

Future Capital Investment

Due to our expectation that low commodity prices will persist for an extended period, we plan to adopt a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies. Capital investment decisions will be subject to the stability of crude oil prices.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2015 has been revised and is now forecast to be between $475 million and $525 million. We plan to focus on sustaining capital related to existing production as well as progressing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day and first production is anticipated in the first half of 2016. Spending related to construction work on phase H was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. If conditions are favourable in the remainder of 2015, we anticipate resuming investment in phase H. Phase H has an initial design capacity of 30,000 gross barrels per day. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrel per day phase.

Christina Lake is producing from phases A through E. Capital investment for 2015 has been revised and is now forecast to be between $675 million and $725 million and we plan to focus on sustaining capital related to existing production, expansion phase F and the optimization project. Expansion work on phase F, including cogeneration, is continuing as planned. We anticipate adding production capacity of 50,000 gross barrels per day from phase F in the second half of 2016. The optimization project is expected to add production capacity of 22,000 gross barrels per day in the fourth quarter of 2015 and ramp up over a twelve month period. Spending on phase G engineering and procurement continued in 2015; however, construction work on phase G was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. If conditions are favourable in the remainder of 2015, we plan to resume investment in phase G to prepare for the possibility of construction work resuming in 2016. Phase G has an initial design capacity of 50,000 gross barrels per day. We submitted a joint application and environmental impact assessment to regulators in March 2013 for the phase H expansion, a 50,000 gross barrel per day phase, for which we expect to receive regulatory approval in the second half of 2015.

Capital investment at Narrows Lake is forecast to be between $30 million and $40 million in 2015. In 2015, we plan to focus our capital investment on detailed engineering and procurement. We suspended new construction on phase A in response to low commodity prices. However, if conditions are favourable, we expect to resume investment in Narrows Lake phase A after the Christina Lake phase G and Foster Creek phase H expansions are funded.

Emerging Projects

Two of our emerging projects are Telephone Lake and Grand Rapids. Capital investment for our new resource plays is forecast to be between $90 million and $100 million in 2015. We plan to focus on continuing the pilot project at Grand Rapids and the dismantling, removal and storage of an existing SAGD facility purchased in 2014; as well as engineering at Telephone Lake. At Grand Rapids, steam circulation continued on the third pilot well pair drilled in the first quarter of 2015.

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. 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, 2014
Upstream Property, Plant and Equipment	14,644
Estimated Future Development Capital	20,084
Total Estimated Upstream Cost Base	34,728
Total Proved Reserves (MMBOE)	2,393
Implied Depletion Rate ($/BOE)	14.51

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 $16.50 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, 2015, Oil Sands DD&A increased $6 million and $33 million, respectively, primarily due to higher sales volumes.

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, our heavy oil asset 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. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment while 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.

In the second quarter of 2015, we reached an agreement to sell our royalty interest and mineral fee title lands business which consists of approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. The associated third-party royalty interest volumes were approximately 7,300 BOE/d in the first half of 2015.

In addition to the sale of our royalty interest and mineral fee title lands business, we entered into lease agreements where we have working interest production. The royalty rates and lease terms are not expected to materially impact our free cash flow currently generated from these assets. To help preserve the future growth and development of our conventional operations, we also retained an option to acquire leases at pre-determined rates and lease terms for up to 10 years on more than 800,000 acres in zones of the fee lands that we are currently developing.

The sale closed on July 29, 2015 for cash proceeds of approximately $3.3 billion. The after-tax gain on the divestiture is estimated to be approximately $1.9 billion, which will be recorded in the third quarter.

Additional developments in our Conventional segment in the second quarter of 2015 compared with 2014 include:
- Crude oil production averaging 69,220 barrels per day, decreasing 10 percent, primarily due to expected natural declines and the divestiture of a non-core asset in 2014; and
- Generating Operating Cash Flow net of capital investment of $263 million, a decrease of 32 percent.

Conventional – Crude Oil

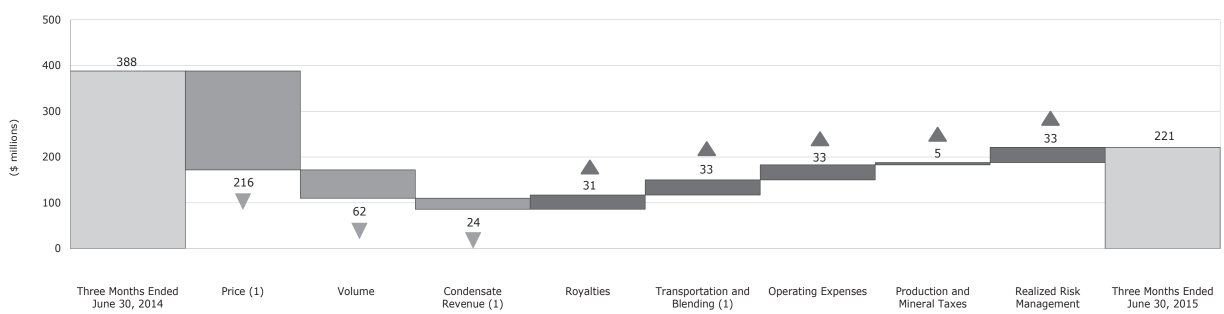
Three Months Ended June 30, 2015 Compared With June 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted [1])	Three Months Ended June 30, 2015	$ per-unit	Three Months Ended June 30, 2014	$ per-unit
Gross Sales	**406**	63	708	99
Less: Royalties	**36**	5	67	9
Revenues	**370**	58	641	90
Expenses				
Transportation and Blending	**58**	9	91	13
Operating	**100**	16	133	19
Production and Mineral Taxes	**5**	1	10	1
(Gain) Loss on Risk Management	**(14)**	(2)	19	3
Operating Cash Flow	**221**	34	388	54
Capital Investment	**34**		149	
Operating Cash Flow Net of Related Capital Investment	**187**		239	

(1) Per-unit amounts are calculated on an unblended crude oil basis.

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 was $56.38 per barrel in the second quarter, 37 percent lower than in 2014, consistent with the decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	2015	Percent Change	2014
Heavy Oil	**36,099**	**(10)%**	40,304
Light and Medium Oil	**31,809**	**(10)%**	35,329
NGLs	**1,312**	**7%**	1,228
	69,220	**(10)%**	76,861

Production declined primarily due to expected natural declines and the divestiture of a non-core asset in 2014, which produced 2,964 barrels per day in the second quarter of 2014.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate.

Royalties

Royalties decreased $31 million primarily due to lower realized sales prices. In the second quarter, the effective crude oil royalty rate for our Conventional properties was 10.2 percent (2014 – 10.8 percent).

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, 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). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. In the second quarter of 2015, the Pelican Lake royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2014.

Approximately 50 percent of our production was not subject to royalties in the second quarter of 2015, but was subject to mineral tax which is generally lower than the royalties paid to the government or other mineral interest owners. In the second quarter of 2015, production and mineral taxes decreased, consistent with the decline in crude oil prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $33 million. Blending costs declined primarily due to lower condensate prices. Transportation charges were $9 million lower primarily due to a reduction in volumes moved by rail. In the second quarter of 2015, we transported an average of 822 gross barrels per day of crude oil by rail (2014 – 2,311 barrels per day).

Operating

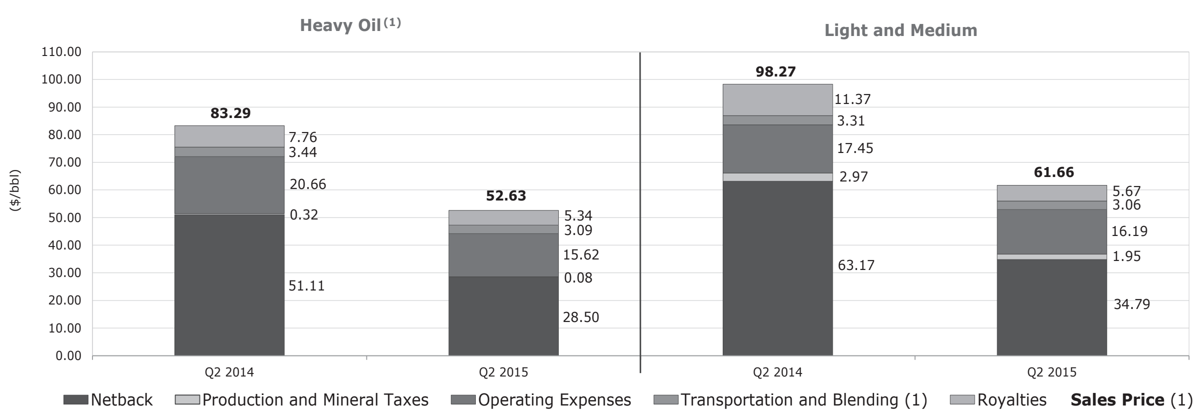
Primary drivers of our operating expenses in the second quarter of 2015 were workforce costs, workover activities, electricity, chemical consumption, and property taxes and lease costs. Operating expenses declined $33 million or $3.31 per barrel.

The per unit decline was primarily due to:

- A decline in workover costs and lower repairs and maintenance due to a focus on critical operational activities; and
- Lower trucking expenses as we added pipeline infrastructure.

These decreases were partially offset by lower production.

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 $12.42 per barrel in the second quarter (2014 – $17.70 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 gains of $14 million (2014 – realized losses of $19 million), consistent with our contract prices exceeding average benchmark prices.

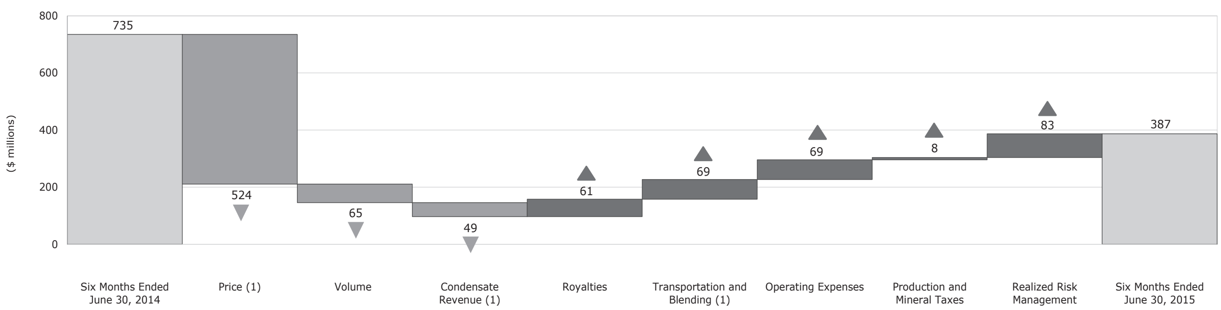
Six Months Ended June 30, 2015 Compared With June 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted [1])	Six Months Ended June 30, 2015		Six Months Ended June 30, 2014	
		$ per-unit		$ per-unit
Gross Sales	**721**	54	1,359	97
Less: Royalties	**55**	4	116	8
Revenues	**666**	50	1,243	89
Expenses				
Transportation and Blending	**111**	8	180	13
Operating	**209**	16	278	20
Production and Mineral Taxes	**10**	1	18	1
(Gain) Loss on Risk Management	**(51)**	(4)	32	2
Operating Cash Flow	**387**	29	735	53
Capital Investment	**96**		412	
Operating Cash Flow Net of Related Capital Investment	**291**		323	

(1) Per-unit amounts are calculated on an unblended crude oil basis.

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 decreased 45 percent to $48.18 per barrel consistent with the sustained decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	2015	Percent Change	2014
Heavy Oil	**36,624**	**(10)%**	40,550
Light and Medium Oil	**33,463**	**(4)%**	34,966
NGLs	**1,335**	**19%**	1,121
	71,422	**(7)%**	76,637

Production declined primarily due to expected natural declines and the divestiture of non-core assets in 2014, which produced 3,069 barrels per day in 2014.

Royalties

Royalties decreased $61 million primarily due to lower realized sales prices. In the first six months of 2015, the effective crude oil royalty rate for our Conventional properties was 9.0 percent (2014 – 10.0 percent). The Pelican Lake royalty calculation was based on net profits in 2015 as compared with a calculation based on gross revenues in 2014.

Production and mineral taxes also decreased on a year-to-date basis, consistent with lower crude oil prices in 2015.

Expenses

Transportation and Blending

Transportation and blending costs decreased $69 million. Blending costs declined primarily due to lower condensate prices. Transportation charges were $20 million lower primarily due to a reduction in volumes moved by rail. In the first half of 2015, we transported an average of 1,204 gross barrels per day of crude oil by rail (2014 – 3,895 barrels per day).

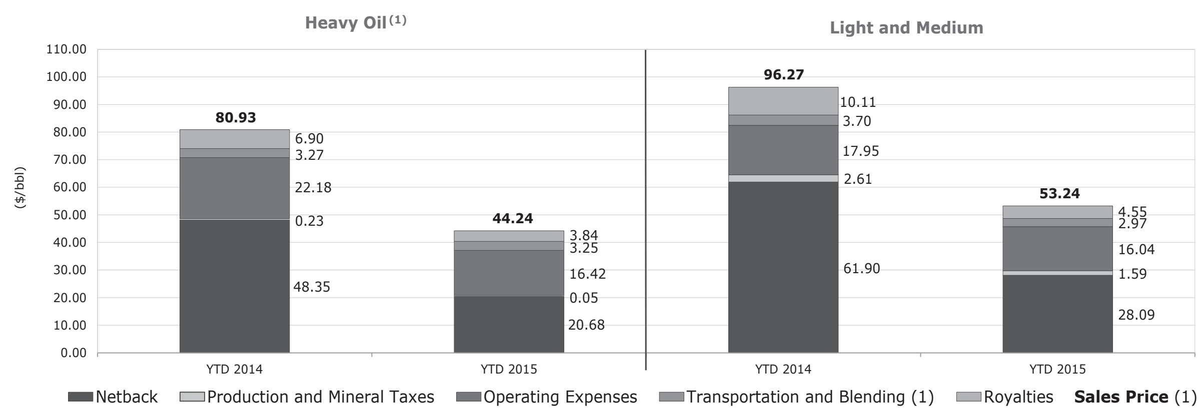
Operating

Primary drivers of our operating expenses in the first six months of 2015 were workforce costs, workover activities, electricity, chemical consumption, and repairs and maintenance. Operating expenses declined $69 million or $4.00 per barrel.

The per unit decline was primarily due to:
- A decline in workover costs and lower repairs and maintenance due to a focus on critical operational activities;
- Lower electricity costs as a result of a decrease in consumption due in part to the disposition of non-core assets, and a decline in prices; and
- Lower trucking expenses as we added pipeline infrastructure.

These decreases were partially offset by lower production.

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 $11.96 per barrel on a year-to-date basis (2014 – $17.63 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

Risk Management

Risk management activities in the first six months of the year resulted in realized gains of $51 million (2014 – realized losses of $32 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Gross Sales	**111**	214	**233**	398
Less: Royalties	**1**	3	**3**	6
Revenues	**110**	211	**230**	392
Expenses				
Transportation and Blending	**4**	4	**9**	9
Operating	**43**	52	**90**	101
Production and Mineral Taxes	**1**	7	**1**	6
(Gain) Loss on Risk Management	**(15)**	1	**(25)**	1
Operating Cash Flow	**77**	147	**155**	275
Capital Investment	**2**	4	**6**	11
Operating Cash Flow Net of Related Capital Investment	**75**	143	**149**	264

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

Three and Six Months Ended June 30, 2015 Compared With June 30, 2014

Revenues

Pricing

In the second quarter and the first half of the year, our average natural gas sales price decreased 42 percent to $2.83 per Mcf and 37 percent to $2.95 per Mcf, respectively, consistent with the decline in the AECO benchmark price.

Production

Production decreased 11 percent to 429 MMcf per day in the second quarter and seven percent to 436 MMcf per day on a year-to-date basis due to expected natural declines.

Royalties

Royalties decreased slightly as a result of lower prices and production declines. The average royalty rate in the second quarter was 1.1 percent (2014 – 1.7 percent) and 1.4 percent (2014 – 1.5 percent) on a year-to-date basis.

Expenses

Transportation

In the three and six months ended June 30, 2015, transportation costs remained consistent as a result of lower production volumes offset by higher pipeline rates.

Operating

In the second quarter and the first half of 2015, our operating expenses were primarily composed of property taxes and lease costs, and workforce. Operating expenses decreased by $9 million and $11 million, respectively, primarily due to lower repairs and maintenance, and workovers, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities resulted in realized gains of $15 million in the second quarter and realized gains of $25 million on a year-to-date basis (2014 – realized losses of $1 million in the second quarter and on a year-to-date basis), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment (1)

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Heavy Oil	**10**	82	**32**	188
Light and Medium Oil	**24**	67	**64**	224
Natural Gas	**2**	4	**6**	11
	36	153	**102**	423

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

Capital investment declined in 2015 primarily due to spending reductions on crude oil activities in response to the low commodity price environment. Capital investment in the first half of 2015 was primarily related to maintenance capital and spending for our CO_2 project at Weyburn.

Conventional Drilling Activity

	Six Months Ended June 30,	
(net wells, unless otherwise stated)	**2015**	2014
Crude Oil	**5**	66
Recompletions	**120**	354
Gross Stratigraphic Test Wells	**-**	14
Other (1)	**-**	24

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

Drilling activity declined in the first six months of 2015, reflecting the decision to suspend the majority of our 2015 drilling program to date in southern Alberta and Saskatchewan as a result of the current low commodity price environment. Drilling activity is expected to resume in the third quarter at our tight oil projects in southeast Alberta and at our CO_2 project at Weyburn.

Future Capital Investment

Consistent with our expectation that commodity prices will continue to be low for a prolonged period of time, we are planning a more moderate approach to developing our conventional crude oil opportunities. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns. Capital investment decisions will be subject to the stability of crude oil prices.

Our 2015 crude oil capital investment forecast has been revised to be between $265 million and $280 million with spending plans mainly focused on maintenance capital and spending for our CO_2 project at Weyburn and development of our tight oil assets.

DD&A and Exploration Expense

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. 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 $16 million and $6 million for the three and six months ended June 30, 2015, respectively.

Exploration Expense

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability have been established are capitalized as E&E assets. If a field, area or project is determined not to be technically feasible and commercially viable or we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

For the three and six months ended June 30, 2015, $21 million (2014 – $nil million) of previously capitalized E&E costs related to certain conventional tight oil exploration assets were deemed not to be commercially viable and technically feasible and were recorded as exploration expense.

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 approach 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. The weakening of the Canadian dollar relative to the U.S. dollar by 11 percent in the three and six months ended June 30, 2015 as compared with 2014 had a positive impact of approximately $51 million and $77 million, respectively, on our refining gross margin.

Significant developments in our Refining and Marketing segment in the second quarter of 2015 compared with 2014 include:

- Reaching an agreement to purchase a crude-by-rail trans-loading facility for $75 million, subject to closing adjustments, to expand our transportation options. The transaction is expected to close in late August 2015;
- Crude oil runs and refined product output decreasing five percent and six percent, respectively, as a result of lower crude utilization due to unplanned outages from process unit outages and a power interruption; and
- Operating Cash Flow increasing 36 percent to $300 million primarily due to improved margins on the sale of secondary products such as coke and asphalt, weakening of the Canadian dollar relative to the U.S. dollar, and an increase in average market crack spreads, partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and a decrease in refined product output.

Refinery Operations [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	**2015**	2014
Crude Oil Capacity [2] (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**441**	466	**440**	433
Heavy Crude Oil	**200**	221	**210**	208
Light/Medium	**241**	245	**230**	225
Refined Products (Mbbls/d)	**462**	489	**465**	458
Gasoline	**241**	240	**239**	228
Distillate	**148**	155	**146**	142
Other	**73**	94	**80**	88
Crude Utilization (percent)	**96**	101	**96**	94

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity, based on 95 percent of the highest average rate achieved over a continuous 30-day period.

On a 100-percent basis, our refineries have total 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 benefits our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In the second quarter of 2015, crude oil runs, refined product output and crude utilization decreased due to unplanned outages at our Borger refinery as a result of process unit outages and a power interruption.

On a year-to-date basis, crude oil runs and refined product output increased slightly as utilization was higher than in 2014. In the first half of 2015, we experienced unplanned outages and completed a planned turnaround at Borger in comparison to completing planned maintenance and turnarounds at both of our refineries in the first half of 2014. Utilization in the third quarter is anticipated to decline due to unplanned outages at our Borger refinery in July.

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 volume of heavy crude oil processed in the second quarter of 2015 decreased from 2014 as a result of processing higher volumes of medium crude oils due to more favorable economics. On a year-to-date basis, the volume of heavy crude oil processed slightly increased, consistent with higher total crude oil runs compared with 2014.

Financial Results

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2015**	2014	**2015**	2014
Revenues	**2,437**	3,483	**4,533**	6,741
Purchased Product	**1,976**	3,098	**3,814**	5,918
Gross Margin	**461**	385	**719**	823
Expenses				
Operating	**160**	165	**337**	363
(Gain) Loss on Risk Management	**1**	-	**(13)**	(5)
Operating Cash Flow	**300**	220	**395**	465
Capital Investment	**48**	46	**92**	69
Operating Cash Flow Net of Related Capital Investment	**252**	174	**303**	396

Gross Margin

Our realized crack spreads are affected by many factors, such as the variety of feedstock crude oil inputs, refinery configuration and the proportion of gasoline, distillate and secondary product output; the time lag between the purchase of crude oil feedstock and the processing of that crude oil through our refineries; and the cost of feedstock. Our feedstock costs are valued on a FIFO accounting basis.

In the second quarter of 2015, the increase in gross margin was primarily due to:

- Improved margins on the sale of secondary products, such as coke and asphalt, due to lower overall feedstock costs consistent with the 44 percent decline in WTI;
- The weakening of the Canadian dollar relative to the U.S. dollar by 11 percent; and
- Average market crack spreads increasing by approximately seven percent, primarily due to stronger global demand for gasoline as a result of weaker pricing.

The increase in gross margin was partially offset by:

- Higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential; and
- A decrease in refined product output due to unplanned outages.

On a year-to-date basis, the decline in gross margin was primarily due to higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential.

The decrease in gross margin was partially offset by:

- Improved margins on the sale of secondary products, due to lower overall feedstock costs consistent with the 47 percent decline in WTI;
- The weakening of the Canadian dollar relative to the U.S. dollar by 11 percent; and
- A slight increase in refined product output.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers ("RINs"). In the second quarter of 2015 and on a year-to-date basis, the cost of our RINs was $40 million and $93 million, respectively (2014 – $30 million and $56 million, respectively). This increase is consistent with the rise in the ethanol RINs benchmark price. This cost remains a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating expenses in the second quarter of 2015 and on a year-to-date basis were labour, maintenance, utilities and supplies. Operating expenses decreased three percent in the second quarter and seven percent on a year-to-date basis compared with 2014 due to a decline in utility costs resulting from lower natural gas prices and a reduction in planned maintenance and turnaround activities. In the first half of 2015, we completed a planned turnaround at Borger in comparison to completing planned maintenance and turnarounds at both of our refineries in the first half of 2014.

Refining and Marketing – Capital Investment

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Wood River Refinery	**34**	23	**61**	34
Borger Refinery	**13**	23	**30**	35
Marketing	**1**	-	**1**	-
	48	46	**92**	69

Capital expenditures in 2015 focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives. We received permit approval in the first quarter of 2015 for the Wood River debottlenecking project and a start-up is anticipated in the second half of 2016.

In 2015, we expect to invest between $240 million and $260 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

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 by $7 million in the second quarter and $14 million on a year-to-date basis, primarily due to the change in the U.S./Canadian dollar 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, our risk management activities resulted in $151 million of unrealized losses (2014 – $11 million of unrealized losses). On a year-to-date basis, we had $296 million of unrealized losses (2014 – $15 million of unrealized gains). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
General and Administrative	**73**	102	**145**	211
Finance Costs	**116**	102	**237**	232
Interest Income	**(3)**	(25)	**(14)**	(27)
Foreign Exchange (Gain) Loss, Net	**(100)**	(187)	**415**	(40)
Research Costs	**7**	4	**14**	6
(Gain) Loss on Divestiture of Assets	**-**	(20)	**(16)**	(20)
Other (Income) Loss, Net	**2**	(1)	**2**	(2)
	95	(25)	**783**	360

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2015 were workforce, office rent and information technology costs. General and administrative expenses decreased by $29 million in the second quarter and $66 million on a year-to-date basis primarily due to lower employee long-term incentive costs driven by the decline in our share price, and lower discretionary spending.

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 increased $14 million in the second quarter compared with 2014 due to higher interest incurred on our U.S. dollar denominated debt due to weakening of the Canadian dollar relative to the U.S. dollar. In the first half of 2015, finance costs increased $5 million from 2014 due to higher interest incurred on our U.S. dollar denominated debt, due to weakening of the Canadian dollar relative to the U.S. dollar, partially offset by lower interest incurred on the Partnership Contribution Payable which was repaid in the first quarter of 2014.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the second quarter was 5.3 percent (2014 – 4.9 percent) and for the six months ended June 30, 2015 was 5.2 percent (2014 – 5.0 percent).

Foreign Exchange

($ millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Unrealized Foreign Exchange (Gain) Loss	**(102)**	(181)	**421**	(38)
Realized Foreign Exchange (Gain) Loss	**2**	(6)	**(6)**	(2)
	(100)	(187)	**415**	(40)

The majority of unrealized foreign exchange gains and losses stem from translation of our U.S. dollar denominated debt. The Canadian dollar strengthened by two percent relative to the U.S. dollar from March 31, 2015 to June 30, 2015 resulting in an unrealized gain in the second quarter, whereas the Canadian dollar weakened by seven percent relative to the U.S. dollar from December 31, 2014 to June 30, 2015 resulting in a year-to-date unrealized loss of $421 million.

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 in the second quarter of 2015 was $21 million (2014 – $21 million) and $42 million on a year-to-date basis (2014 – $41 million).

Income Tax

($ millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Current Tax				
Canada	**321**	(10)	**235**	33
United States	**(6)**	3	**(6)**	35
Total Current Tax	**315**	(7)	**229**	68
Deferred Tax	**(261)**	216	**(288)**	252
	54	209	**(59)**	320

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

($ millions)	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Earnings (Loss) Before Income Tax	**(601)**	1,182
Canadian Statutory Rate	**26.1%**	25.2%
Expected Income Tax	**(157)**	298
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**4**	25
Non-Deductible Stock-Based Compensation	**5**	10
Non-Taxable Capital Losses	**56**	7
Unrecognized Capital Losses Arising from Unrealized Foreign Exchange	**56**	7
Adjustments Arising From Prior Year Tax Filings	**(11)**	-
Recognition of Capital Losses	**(149)**	(4)
Change in Statutory Rate	**168**	-
Other	**(31)**	(23)
Total Tax	**(59)**	320
Effective Tax Rate	**9.8%**	27.1%

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 and as a result 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.

Effective July 1, 2015, the Alberta corporate income tax rate increased from 10 percent to 12 percent, increasing our Canadian statutory tax rate. This change had a significant impact on both current and deferred tax in the second quarter as our Canadian operations are mainly in Alberta.

Current tax in the three and six months ended June 30, 2015 increased primarily due to accelerating the timing of income tax payable as a result of certain corporate restructuring transactions and the decision to maximize availability of future income tax deductions in response to the Alberta corporate income tax rate increase.

In the three and six months ended June 30, 2015, a deferred tax recovery was recorded. The recovery is largely due to the reversal of timing differences associated with the recognition of partnership income and unrealized risk management losses, the recognition of a benefit from capital losses not previously recognized, and current year operating losses, partially offset by a one-time charge of approximately $168 million from the revaluation of the deferred tax liability due to the increase in the Alberta corporate tax rate. The benefit of the capital losses was recognized as a result of the agreement to dispose of the royalty interest and mineral fee title lands business.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes. The effective tax rate differs from the statutory tax rate as it reflects higher U.S. tax rates, permanent differences, adjustments for changes in tax rates and other tax legislation, variations in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

Our effective tax rate for 2015 differs from the statutory rate due to a one-time deferred tax expense arising from the Alberta corporate income tax rate increase and non-deductible foreign exchange losses, partially offset by the recognition of the benefit of capital losses and favourable adjustments related to prior years.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2015**	2014	**2015**	2014
Net Cash From (Used In)				
Operating Activities	**335**	1,109	**610**	1,566
Investing Activities	**(424)**	(692)	**(1,067)**	(3,089)
Net Cash Provided (Used) Before Financing Activities	**(89)**	417	**(457)**	(1,523)
Financing Activities	**(126)**	(471)	**1,166**	(225)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**1**	(1)	**(2)**	56
Increase (Decrease) in Cash and Cash Equivalents	**(214)**	(55)	**707**	(1,692)

	June 30, 2015	December 31, 2014
Cash and Cash Equivalents	**1,590**	883

Operating Activities

Cash from operating activities was $774 million and $956 million lower for the three and six months ended June 30, 2015 mainly due to lower 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, working capital was $1,934 million at June 30, 2015 compared with $772 million at December 31, 2014. The increase in working capital was primarily due to the proceeds received from the common share issuance in the first quarter of 2015.

We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In the second quarter of 2015, cash used in investing activities was $424 million, a $268 million decrease from 2014, mainly driven by reduced capital expenditures in response to the low commodity price environment.

On a year-to-date basis, cash used in investing activities was $1,067 million, a $2,022 million decrease from 2014, primarily due to the repayment of the US$1.4 billion Partnership Contribution Payable in March 2014.

Financing Activities

Cash used in financing activities decreased $345 million for the three months ended June 30, 2015, primarily due to cash savings from our DRIP and a net repayment of short-term borrowings in 2014.

Cash provided by financing activities increased $1,391 million for the six months ended June 30, 2015, primarily due to net proceeds from our common share issuance and cash savings from our DRIP, partially offset by a net repayment of short-term borrowings. In the first half of 2015, we had a net repayment of short-term borrowings compared with a net issuance in 2014. In the first quarter of 2015, we issued 67.5 million common shares at a price of $22.25 per share for net proceeds of $1.4 billion. We plan to use the net proceeds to partially fund our capital expenditure program for 2015 and for general corporate purposes.

In the second quarter, we paid dividends of $0.2662 per share or $223 million (2014 – $0.2662 per share or $201 million), of which $125 million was paid in cash with the remainder reinvested in common shares issued from treasury through our DRIP (2014 – $201 million paid in cash). On a year-to-date basis, we paid dividends of $0.5324 per share or $445 million (2014 – $0.5324 per share or $403 million), of which $263 million was paid in cash (2014 – $403 million paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. While the DRIP continues to be in place, the discount has been discontinued.

Our long-term debt at June 30, 2015 was $5,875 million (December 31, 2014 – $5,458 million) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $417 million increase in long-term debt is due to foreign exchange.

As at June 30, 2015, we were 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 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, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

The following sources of liquidity are available at June 30, 2015:

($ millions)	Amount	Term
Cash and Cash Equivalents	**1,590**	**Not applicable**
Committed Credit Facility	**1,000**	**November 2017**
Committed Credit Facility	**3,000**	**November 2019**
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.

Committed Credit Facility

During the second quarter, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2019. In addition, a new $1.0 billion tranche was established under the same facility, maturing on November 30, 2017. As at June 30, 2015, the Company had $4.0 billion available on its committed credit facility.

We have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve undrawn capacity under our committed credit facility for amounts of outstanding commercial paper. As of June 30, 2015, there was no commercial paper outstanding.

U.S. and Canadian Base Shelf Prospectuses

As at June 30, 2015, no notes were issued under our U.S. or Canadian base shelf prospectuses.

Divestiture of Royalty Business

The divestiture of our royalty interest and mineral fee title lands business closed on July 29, 2015, increasing our cash-on-hand by approximately $3.3 billion.

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. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill and 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 twelve-month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

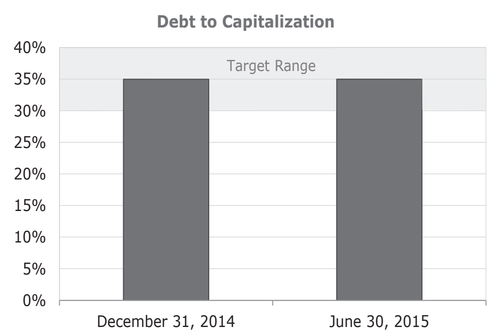
As at	**June 30, 2015**	December 31, 2014
Debt to Capitalization	**35%**	35%
Net Debt to Capitalization [1] [2]	**28%**	31%
Debt to Adjusted EBITDA (times)	**2.1x**	1.4x
Net Debt to Adjusted EBITDA (times) [1]	**1.5x**	1.2x

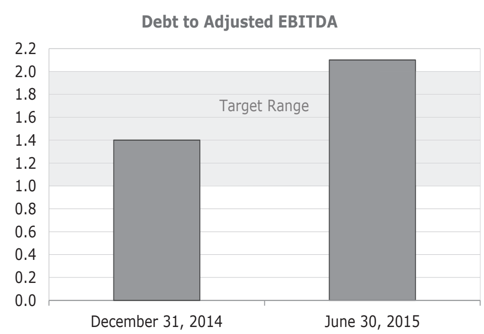
(1) Net Debt is defined as Debt net of cash and cash equivalents.
(2) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

The sale of our royalty interest and mineral fee title lands business will generate cash proceeds of approximately $3.3 billion. If the transaction had closed on June 30, 2015, Net Debt to Capitalization and Net Debt to Adjusted EBITDA would have been seven percent and 0.3x, respectively.

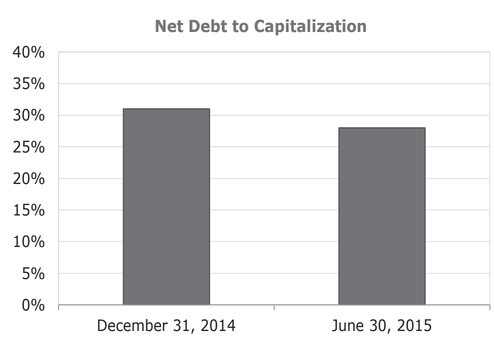
We continue to have long-term targets for a Debt to Capitalization ratio of between 30 percent to 40 percent and a Debt to Adjusted EBITDA of between 1.0 times to 2.0 times. At June 30, 2015, our Debt to Capitalization metric was within our target range. Although our Debt to Adjusted EBITDA ratio was above our target of 2.0 times as at June 30, 2015, we believe it will return to within our target range.

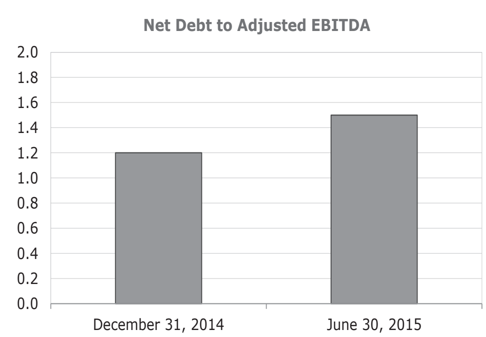
Debt to Capitalization remained consistent as higher debt balances from the weakening of the Canadian dollar relative to the U.S. dollar were offset by the increase in Shareholders' Equity as a result of the common share issuance. The increase in Debt to Adjusted EBITDA was due to higher debt balances as a result of foreign exchange and lower Adjusted EBITDA primarily due to a decline in Operating Cash Flow as a result of low commodity prices.





As at June 30, 2015, we held $1.6 billion in cash and cash equivalents. Net Debt to Capitalization and Net Debt to Adjusted EBIDTA were 28 percent and 1.5 times, respectively (December 31, 2014 – 31 percent and 1.2 times, respectively).





Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

Outstanding Share Data and Stock-Based Compensation Plans

Cenovus is authorized to issue an unlimited number of common shares, and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. At June 30, 2015, no preferred shares were outstanding. Cenovus issued 76.2 million common shares during the six months ended June 30, 2015, including 8.7 million shares issued under the DRIP and 67.5 million shares issued related to the common share issuance in the first quarter of 2015.

The DRIP permits shareholders to reinvest their dividends into additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. For the first and second quarters of 2015, participants in our DRIP were issued shares from treasury at a three percent discount to the average market price, as defined in the DRIP. For the second quarter dividend, the participation rate in the DRIP was approximately 43 percent and resulted in $96 million of cash savings. On a year-to-date basis, the DRIP resulted in $177 million of cash savings. While the DRIP continues to be in place, the discount has been discontinued. Refer to cenovus.com for more details.

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 our Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit Plans.

PSUs and RSUs 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 Note 27 of the Consolidated Financial Statements and Note 18 of our interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at June 30, 2015	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**47,413**	**27,313**
Other Stock-Based Compensation Plans	**11,467**	**1,416**

Contractual Obligations and Commitments

We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. 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 Consolidated Financial Statements.

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 2014 annual MD&A. 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, 2014.

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. We continue to be exposed to the risks identified in our 2014 annual MD&A in addition to jurisdictional risk.

The following provides an update on our commodity price risk management and jurisdictional risk.

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 business integration, financial hedges and physical contracts. 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 Note 21 to the interim Consolidated Financial Statements. The financial impact is summarized below:

Impact of Financial Risk Management Activities

	Three Months Ended June 30,					
	2015			2014		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	(32)	142	110	52	12	64
Natural Gas	(16)	15	(1)	1	(3)	(2)
Refining	2	3	5	-	3	3
Power	-	(9)	(9)	2	(1)	1
(Gain) Loss on Risk Management	(46)	151	105	55	11	66
Income Tax Expense (Recovery)	14	(45)	(31)	(14)	(3)	(17)
(Gain) Loss on Risk Management, After Tax	(32)	106	74	41	8	49

	Six Months Ended June 30,					
	2015			2014		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	(160)	261	101	86	(14)	72
Natural Gas	(28)	26	(2)	1	(2)	(1)
Refining	(12)	12	-	(4)	2	(2)
Power	3	(3)	-	2	(1)	1
(Gain) Loss on Risk Management	(197)	296	99	85	(15)	70
Income Tax Expense (Recovery)	54	(82)	(28)	(21)	4	(17)
(Gain) Loss on Risk Management, After Tax	(143)	214	71	64	(11)	53

In the second quarter and the first half of 2015, management of commodity price risk resulted in realized gains on crude oil and natural gas financial instruments, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized losses on our crude oil and natural gas financial instruments primarily due to the realization of settled positions and changes in market prices.

Jurisdictional Risk

The newly elected Alberta NDP provincial government is proceeding with plans to study, and potentially modify, Alberta's royalty structure and increase carbon levies. A change in the Alberta provincial royalty structure could have a significant impact on Cenovus's future financial results, cost of capital and capital investment plans. We are cautiously awaiting the results of the planned royalty review before finalizing plans to begin reinvesting capital in previously deferred oil sands expansion projects.

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 2014 annual MD&A.

Management is 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, 2014.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. There have been no changes to our critical judgments used in applying accounting policies in the first six months of 2015. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014.

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 recorded 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 2015. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the six months ended June 30, 2015.

Future Accounting Pronouncements

Revenue Recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing International Accounting Standard 11, "*Construction Contracts*", International Accounting Standard 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.

On July 22, 2015, the IASB announced an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. Early adoption is still 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.

Additional Standards

A description of additional standards and interpretations that will be adopted in future periods can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2014.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") in the three months ended June 30, 2015 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 are available on our website at cenovus.com.

In June 2015, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the fourth year in a row and for the fifth consecutive year by Corporate Knights magazine as one of the 2015 Best 50 Corporate Citizens in Canada. We were also included in the Euronext Vigeo World 120 Index for the second year. 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 2015, Cenovus was named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the third consecutive year. In January 2015, Cenovus was included in the RobecoSAM Sustainability Yearbook for the second time in a row. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index ("DJSI"). Cenovus continues to be named to the DJSI family of indices and is currently listed on the DJSI World and DJSI North American Index. Cenovus is also part of the FTSE4Good Index series and the MSCI Global Sustainability Index series. These internationally recognized benchmarks are designed to measure the performance of companies demonstrating strong environmental, social and governance practices.

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

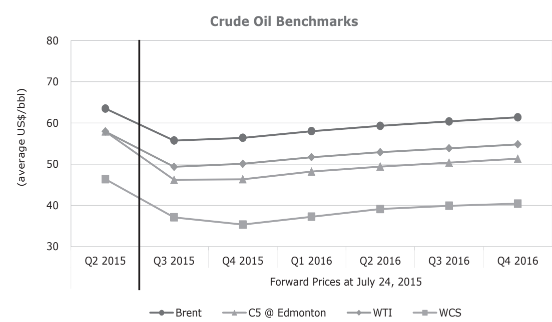
OUTLOOK

We expect the second half of 2015 to continue to be a challenging time for our industry. Although benchmark commodity prices improved slightly in the second quarter, forward prices have declined from June 30 and we anticipate prices will remain low throughout the remainder of 2015. We revised our 2015 budget in January, reducing our capital spending plans and introducing other initiatives intended to conserve cash and maintain the strength of our balance sheet. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexible capital plans. We continue to pursue our long-term strategy at a pace we believe is in line with the current commodity price environment.

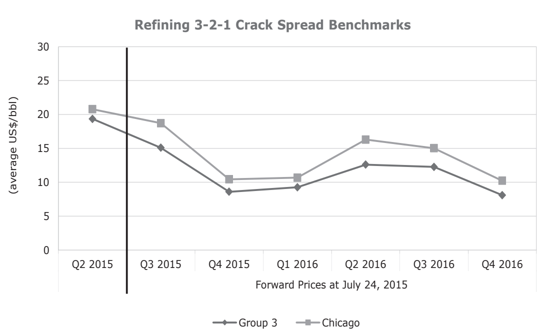
The following outlook commentary is focused on the next eighteen months.

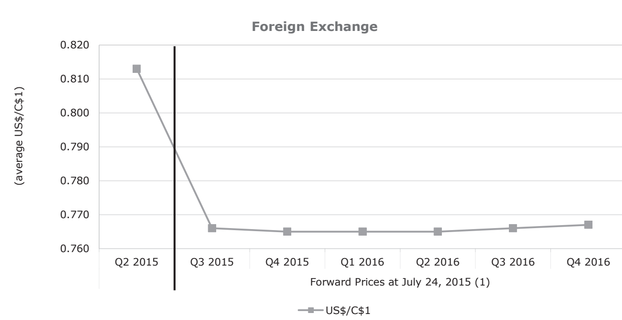
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:



- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment and the pace of growth of the global economy. Overall, we expect crude oil price volatility in the second half of 2015 and a modest price improvement in 2016. Slower global supply growth, combined with annual increases in demand growth, should support prices for the next eighteen months, constrained by the need to draw down surplus crude oil inventories and anticipated re-entry of Iranian crude oil into markets. We continue to anticipate slower supply growth from North American producers as a result of the significant reductions in capital spending. The current low crude oil price environment also serves to help boost global economic momentum. We believe there is a risk that OPEC will attempt to gain market share by increasing rig counts or increasing OPEC production which will depress prices;
- We expect the Brent-WTI differential to remain near current levels primarily because of slower U.S. supply growth, which should prevent congestion in the U.S. market and cause the differential to be set by transportation costs. The Brent-WTI differential is expected to remain volatile due to mismatches in demand, global imports and refinery turnarounds; and
- We expect the WTI-WCS differential to widen from currently narrow levels due to supply returning from outages caused by forest fires and maintenance activities. However, substantially wider differentials are unlikely due to excess rail capacity and further expansions on existing pipeline systems.





(1) Refer to the foreign exchange rate sensitivities found within our current guidance available at cenovus.com.

For the next eighteen months, we expect crack spreads to remain close to levels experienced over the past twelve months, with some seasonal variation.

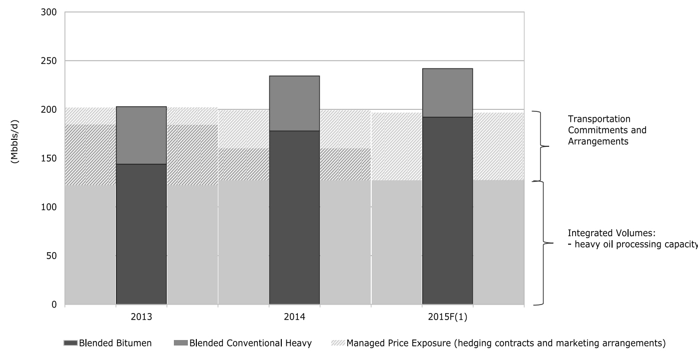
Natural gas prices are expected to remain weak throughout the next eighteen months. The inventory of drilled but uncompleted wells should keep supply growth strong despite a sharp decline in industry activity. Coal-to-gas substitution in the power sector is expected to be required to correct anticipated high storage levels before the winter season.

The average foreign exchange forward price expected over the next eighteen months is US$0.800/C$. Timing of key interest rate decisions, both in Canada and the U.S., and U.S. economic momentum are expected to dictate future foreign exchange fluctuations. Overall, we expect the Canadian dollar to remain relatively weak compared with the U.S. dollar, which should have a positive impact on our revenues and Operating Cash Flow.

Our exposure to the light/heavy price differentials is composed of both a global light/heavy component as well as Canadian congestion. While we expect to see volatility in crude oil prices, we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy oil. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude oil 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 and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets and also to tidewater markets.

Protection Against Canadian Congestion



(1) Expected gross production capacity.

Key Priorities for 2015

Maintain Financial Resilience

We have strong producing assets, an integrated portfolio and a solid balance sheet which should position us well to face the challenges of 2015. Together, our share issuance in the first quarter of 2015 and the sale of our royalty interest and mineral fee title lands business in July 2015 raised cash proceeds of approximately $4.7 billion. These transactions strengthen our balance sheet and provide us with greater financial resilience during these uncertain times to consider investing in opportunities within Cenovus that we believe have strong future returns.

With an additional $3.3 billion of cash on hand after the divestiture of our royalty interest and mineral fee title lands business, we are planning to reinvest capital into expansion projects that were previously deferred to 2016. If market conditions are favourable, we plan to invest approximately $25 million in Christina Lake phase G and approximately $2 million in Foster Creek phase H in the second half of 2015 in preparation to resume construction in 2016. In addition, approximately $70 million has been directed towards further drilling at our tight oil projects in southeastern Alberta and at our Weyburn project in Saskatchewan.

With the decline in crude oil prices and the reduction of future cash flow due to the sale of our royalty interest and mineral fee title lands business, our Board has reduced the third quarter dividend by 40 percent.

Our capital planning process remains flexible. We plan to adopt a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging opportunities only when we believe we will maximize cost savings and capital efficiencies to generate the greatest potential return for shareholders. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in the second half of 2015.

Attack Cost Structures

We continue to challenge 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 maximize the strengths of our functional business model. We previously identified opportunities to achieve between $400 million and $500 million in anticipated sustainable capital and operating cost reductions over the long term. In the first half of 2015, we captured significant savings from capital, operating and general and administrative cost reductions. As a result, we anticipate savings of approximately $280 million for the full year. In light of our plan to moderate our pace of growth and the challenges associated with the continuing low crude oil price environment, we plan to further assess our workforce and general and administrative requirements.

Enable Market Access

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production, as illustrated by our agreement to purchase a crude-by-rail trans-loading facility. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 percent to 20 percent of our crude oil production to market by rail, assessing options to maximize the value of our oil by offering a wider range of products, including existing dilbit blends, under-blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

Other Key Challenges

The newly elected Alberta NDP provincial government is proceeding with plans to study, and potentially modify, Alberta's royalty structure and increase carbon levies. A change in the Alberta provincial royalty structure could have a significant impact on Cenovus's future financial results, cost of capital and capital investment plans.

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.

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME (unaudited)

For the period ended June 30,
($ millions, except per share amounts)

	Notes	Three Months Ended 2015	Three Months Ended 2014	Six Months Ended 2015	Six Months Ended 2014
Revenues	1				
Gross Sales		**3,779**	5,560	**6,944**	10,675
Less: Royalties		**53**	138	**77**	241
		3,726	5,422	**6,867**	10,434
Expenses	1				
Purchased Product		**1,908**	2,880	**3,640**	5,459
Transportation and Blending		**498**	655	**1,026**	1,308
Operating		**430**	518	**906**	1,090
Production and Mineral Taxes		**6**	17	**11**	24
(Gain) Loss on Risk Management	20	**105**	66	**99**	70
Depreciation, Depletion and Amortization	11	**483**	486	**982**	940
Exploration Expense	10	**21**	1	**21**	1
General and Administrative		**73**	102	**145**	211
Finance Costs	4	**116**	102	**237**	232
Interest Income		**(3)**	(25)	**(14)**	(27)
Foreign Exchange (Gain) Loss, Net	5	**(100)**	(187)	**415**	(40)
Research Costs		**7**	4	**14**	6
(Gain) Loss on Divestiture of Assets	13	**-**	(20)	**(16)**	(20)
Other (Income) Loss, Net		**2**	(1)	**2**	(2)
Earnings (Loss) Before Income Tax		**180**	824	**(601)**	1,182
Income Tax Expense (Recovery)	6	**54**	209	**(59)**	320
Net Earnings (Loss)		**126**	615	**(542)**	862
Other Comprehensive Income (Loss), Net of Tax	17				
Items That Will Not be Reclassified to Profit or Loss:					
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**10**	3	**9**	(5)
Items That May be Reclassified to Profit or Loss:					
Foreign Currency Translation Adjustment		**(54)**	(111)	**218**	(41)
Total Other Comprehensive Income (Loss), Net of Tax		**(44)**	(108)	**227**	(46)
Comprehensive Income (Loss)		**82**	507	**(315)**	816
Net Earnings (Loss) Per Common Share	7				
Basic		**$0.15**	$0.81	**$(0.67)**	$1.14
Diluted		**$0.15**	$0.81	**$(0.67)**	$1.14

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at
($ millions)

	Notes	June 30, 2015	December 31, 2014
Assets			
Current Assets			
Cash and Cash Equivalents		**1,590**	883
Accounts Receivable and Accrued Revenues		**1,358**	1,582
Income Tax Receivable		**15**	28
Inventories	8	**1,291**	1,224
Risk Management	20,21	**187**	478
Assets Held for Sale	9	**926**	-
Current Assets		**5,367**	4,195
Exploration and Evaluation Assets	1,10	**1,697**	1,625
Property, Plant and Equipment, Net	1,11	**17,786**	18,563
Other Assets		**75**	70
Goodwill	1	**242**	242
Total Assets		**25,167**	24,695
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities		**1,992**	2,588
Income Tax Payable		**328**	357
Risk Management	20,21	**13**	12
Liabilities Related to Assets Held for Sale	9	**2**	-
Current Liabilities		**2,335**	2,957
Long-Term Debt	14	**5,875**	5,458
Risk Management	20,21	**7**	4
Decommissioning Liabilities	15	**2,632**	2,616
Other Liabilities		**149**	172
Deferred Income Taxes		**3,074**	3,302
Total Liabilities		**14,072**	14,509
Shareholders' Equity		**11,095**	10,186
Total Liabilities and Shareholders' Equity		**25,167**	24,695

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(unaudited)
($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI [1]	Total
	(Note 16)			(Note 17)	
Balance as at December 31, 2013	3,857	4,219	1,660	210	9,946
Net Earnings	-	-	862	-	862
Other Comprehensive Income (Loss)	-	-	-	(46)	(46)
Total Comprehensive Income (Loss)	-	-	862	(46)	816
Common Shares Issued Under Stock Option Plans	30	-	-	-	30
Stock-Based Compensation Expense	-	39	-	-	39
Dividends on Common Shares	-	-	(403)	-	(403)
Balance as at June 30, 2014	3,887	4,258	2,119	164	10,428
Balance as at December 31, 2014	3,889	4,291	1,599	407	10,186
Net Earnings (Loss)	-	-	(542)	-	(542)
Other Comprehensive Income (Loss)	-	-	-	227	227
Total Comprehensive Income (Loss)	-	-	(542)	227	(315)
Common Shares Issued for Cash	1,463	-	-	-	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	182	-	-	-	182
Common Shares Issued Under Stock Option Plans	-	-	-	-	-
Stock-Based Compensation Expense	-	24	-	-	24
Dividends on Common Shares	-	-	(445)	-	(445)
Balance as at June 30, 2015	**5,534**	**4,315**	**612**	**634**	**11,095**

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the period ended June 30,
($ millions)

	Notes	Three Months Ended 2015	Three Months Ended 2014	Six Months Ended 2015	Six Months Ended 2014
Operating Activities					
Net Earnings (Loss)		**126**	615	**(542)**	862
Depreciation, Depletion and Amortization	11	**483**	486	**982**	940
Exploration Expense		**21**	1	**21**	1
Deferred Income Taxes	6	**(261)**	216	**(288)**	252
Unrealized (Gain) Loss on Risk Management	20	**151**	11	**296**	(15)
Unrealized Foreign Exchange (Gain) Loss	5	**(102)**	(181)	**421**	(38)
(Gain) Loss on Divestiture of Assets	13	**-**	(20)	**(16)**	(20)
Unwinding of Discount on Decommissioning Liabilities	4,15	**31**	30	**62**	60
Other		**28**	31	**36**	51
		477	1,189	**972**	2,093
Net Change in Other Assets and Liabilities		**(14)**	(27)	**(68)**	(69)
Net Change in Non-Cash Working Capital		**(128)**	(53)	**(294)**	(458)
Cash From Operating Activities		**335**	1,109	**610**	1,566
Investing Activities					
Capital Expenditures – Exploration and Evaluation Assets	10	**(20)**	(39)	**(94)**	(143)
Capital Expenditures – Property, Plant and Equipment	11	**(337)**	(653)	**(792)**	(1,378)
Proceeds From Divestiture of Assets	13	**-**	39	**16**	40
Net Change in Investments and Other		**(2)**	-	**-**	(1,579)
Net Change in Non-Cash Working Capital		**(65)**	(39)	**(197)**	(29)
Cash (Used in) Investing Activities		**(424)**	(692)	**(1,067)**	(3,089)
Net Cash Provided (Used) Before Financing Activities		**(89)**	417	**(457)**	(1,523)
Financing Activities					
Net Issuance (Repayment) of Short-Term Borrowings		**-**	(273)	**(19)**	153
Common Shares Issued, Net of Issuance Costs	16	**-**	-	**1,449**	-
Common Shares Issued Under Stock Option Plans		**-**	4	**-**	26
Dividends Paid on Common Shares	7	**(125)**	(201)	**(263)**	(403)
Other		**(1)**	(1)	**(1)**	(1)
Cash From (Used in) Financing Activities		**(126)**	(471)	**1,166**	(225)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**1**	(1)	**(2)**	56
Increase (Decrease) in Cash and Cash Equivalents		**(214)**	(55)	**707**	(1,692)
Cash and Cash Equivalents, Beginning of Period		**1,804**	815	**883**	2,452
Cash and Cash Equivalents, End of Period		**1,590**	760	**1,590**	760

See accompanying Notes to Consolidated Financial Statements (unaudited).

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. and its subsidiaries, (together "Cenovus" or the "Company") are in the business of the development, production and marketing of crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S.").

Cenovus is incorporated under the *Canada Business Corporations Act* and its shares are listed on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada, T2G 1A6. Information on the Company's basis of preparation for these interim Consolidated Financial Statements is found in Note 2.

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating cash flow. The Company's reportable segments are:

- **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 responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Corporate and Eliminations,** which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. 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 following tabular financial information presents the segmented information first by segment, then by product and geographic location.

A) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the three months ended June 30,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**891**	1,369	**519**	926	**2,437**	3,483
Less: Royalties	**16**	68	**37**	70	**-**	-
	875	1,301	**482**	856	**2,437**	3,483
Expenses						
Purchased Product	**-**	-	**-**	-	**1,976**	3,098
Transportation and Blending	**436**	560	**62**	95	**-**	-
Operating	**128**	168	**144**	186	**160**	165
Production and Mineral Taxes	**-**	-	**6**	17	**-**	-
(Gain) Loss on Risk Management	**(18)**	35	**(29)**	20	**1**	-
Operating Cash Flow	**329**	538	**299**	538	**300**	220
Depreciation, Depletion and Amortization	**158**	152	**259**	275	**45**	38
Exploration Expense	**-**	1	**21**	-	**-**	-
Segment Income (Loss)	**171**	385	**19**	263	**255**	182

	Corporate and Eliminations		Consolidated	
For the three months ended June 30,	**2015**	2014	**2015**	2014
Revenues				
Gross Sales	**(68)**	(218)	**3,779**	5,560
Less: Royalties	**-**	-	**53**	138
	(68)	(218)	**3,726**	5,422
Expenses				
Purchased Product	**(68)**	(218)	**1,908**	2,880
Transportation and Blending	**-**	-	**498**	655
Operating	**(2)**	(1)	**430**	518
Production and Mineral Taxes	**-**	-	**6**	17
(Gain) Loss on Risk Management	**151**	11	**105**	66
	(149)	(10)	**779**	1,286
Depreciation, Depletion and Amortization	**21**	21	**483**	486
Exploration Expense	**-**	-	**21**	1
Segment Income (Loss)	**(170)**	(31)	**275**	799
General and Administrative	**73**	102	**73**	102
Finance Costs	**116**	102	**116**	102
Interest Income	**(3)**	(25)	**(3)**	(25)
Foreign Exchange (Gain) Loss, Net	**(100)**	(187)	**(100)**	(187)
Research Costs	**7**	4	**7**	4
(Gain) Loss on Divestiture of Assets	**-**	(20)	**-**	(20)
Other (Income) Loss, Net	**2**	(1)	**2**	(1)
	95	(25)	**95**	(25)
Earnings Before Income Tax			**180**	824
Income Tax Expense			**54**	209
Net Earnings			**126**	615

B) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2015	2014	2015	2014	2015	2014
Revenues						
Gross Sales	884	1,345	406	708	1,290	2,053
Less: Royalties	16	67	36	67	52	134
	868	1,278	370	641	1,238	1,919
Expenses						
Transportation and Blending	435	559	58	91	493	650
Operating	123	166	100	133	223	299
Production and Mineral Taxes	-	-	5	10	5	10
(Gain) Loss on Risk Management	(17)	35	(14)	19	(31)	54
Operating Cash Flow	327	518	221	388	548	906

(1) Includes NGLs.

	Natural Gas					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2015	2014	2015	2014	2015	2014
Revenues						
Gross Sales	5	22	111	214	116	236
Less: Royalties	-	1	1	3	1	4
	5	21	110	211	115	232
Expenses						
Transportation and Blending	1	1	4	4	5	5
Operating	4	5	43	52	47	57
Production and Mineral Taxes	-	-	1	7	1	7
(Gain) Loss on Risk Management	(1)	-	(15)	1	(16)	1
Operating Cash Flow	1	15	77	147	78	162

	Other					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2015	2014	2015	2014	2015	2014
Revenues						
Gross Sales	2	2	2	4	4	6
Less: Royalties	-	-	-	-	-	-
	2	2	2	4	4	6
Expenses						
Transportation and Blending	-	-	-	-	-	-
Operating	1	(3)	1	1	2	(2)
Production and Mineral Taxes	-	-	-	-	-	-
(Gain) Loss on Risk Management	-	-	-	-	-	-
Operating Cash Flow	1	5	1	3	2	8

	Total Upstream					
	Oil Sands		Conventional		Total	
For the three months ended June 30,	2015	2014	2015	2014	2015	2014
Revenues						
Gross Sales	891	1,369	519	926	1,410	2,295
Less: Royalties	16	68	37	70	53	138
	875	1,301	482	856	1,357	2,157
Expenses						
Transportation and Blending	436	560	62	95	498	655
Operating	128	168	144	186	272	354
Production and Mineral Taxes	-	-	6	17	6	17
(Gain) Loss on Risk Management	(18)	35	(29)	20	(47)	55
Operating Cash Flow	329	538	299	538	628	1,076

C) Geographic Information

	Canada		United States		Consolidated	
For the three months ended June 30,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**1,867**	2,822	**1,912**	2,738	**3,779**	5,560
Less: Royalties	**53**	138	**-**	-	**53**	138
	1,814	2,684	**1,912**	2,738	**3,726**	5,422
Expenses						
Purchased Product	**444**	519	**1,464**	2,361	**1,908**	2,880
Transportation and Blending	**498**	655	**-**	-	**498**	655
Operating	**278**	361	**152**	157	**430**	518
Production and Mineral Taxes	**6**	17	**-**	-	**6**	17
(Gain) Loss on Risk Management	**100**	63	**5**	3	**105**	66
	488	1,069	**291**	217	**779**	1,286
Depreciation, Depletion and Amortization	**438**	448	**45**	38	**483**	486
Exploration Expense	**21**	1	**-**	-	**21**	1
Segment Income (Loss)	**29**	620	**246**	179	**275**	799

The Oil Sands and Conventional segments operate in Canada. Both of Cenovus's refining facilities are located and carry on business in the U.S. The marketing of Cenovus's crude oil and natural gas produced in Canada, as well as the third-party purchases and sales of product, is undertaken in Canada. Physical product sales that settle in the U.S. are considered to be export sales undertaken by a Canadian business. The Corporate and Eliminations segment is attributed to Canada, with the exception of the unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

D) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the six months ended June 30,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**1,623**	2,629	**962**	1,764	**4,533**	6,741
Less: Royalties	**19**	119	**58**	122	**-**	-
	1,604	2,510	**904**	1,642	**4,533**	6,741
Expenses						
Purchased Product	**-**	-	**-**	-	**3,814**	5,918
Transportation and Blending	**906**	1,119	**120**	189	**-**	-
Operating	**272**	349	**301**	381	**337**	363
Production and Mineral Taxes	**-**	-	**11**	24	**-**	-
(Gain) Loss on Risk Management	**(108)**	57	**(76)**	33	**(13)**	(5)
Operating Cash Flow	**534**	985	**548**	1,015	**395**	465
Depreciation, Depletion and Amortization	**328**	295	**521**	527	**91**	77
Exploration Expense	**-**	1	**21**	-	**-**	-
Segment Income (Loss)	**206**	689	**6**	488	**304**	388

	Corporate and Eliminations		Consolidated	
For the six months ended June 30,	**2015**	2014	**2015**	2014
Revenues				
Gross Sales	**(174)**	(459)	**6,944**	10,675
Less: Royalties	**-**	-	**77**	241
	(174)	(459)	**6,867**	10,434
Expenses				
Purchased Product	**(174)**	(459)	**3,640**	5,459
Transportation and Blending	**-**	-	**1,026**	1,308
Operating	**(4)**	(3)	**906**	1,090
Production and Mineral Taxes	**-**	-	**11**	24
(Gain) Loss on Risk Management	**296**	(15)	**99**	70
	(292)	18	**1,185**	2,483
Depreciation, Depletion and Amortization	**42**	41	**982**	940
Exploration Expense	**-**	-	**21**	1
Segment Income (Loss)	**(334)**	(23)	**182**	1,542
General and Administrative	**145**	211	**145**	211
Finance Costs	**237**	232	**237**	232
Interest Income	**(14)**	(27)	**(14)**	(27)
Foreign Exchange (Gain) Loss, Net	**415**	(40)	**415**	(40)
Research Costs	**14**	6	**14**	6
(Gain) Loss on Divestiture of Assets	**(16)**	(20)	**(16)**	(20)
Other (Income) Loss, Net	**2**	(2)	**2**	(2)
	783	360	**783**	360
Earnings (Loss) Before Income Tax			**(601)**	1,182
Income Tax Expense (Recovery)			**(59)**	320
Net Earnings (Loss)			**(542)**	862

E) Financial Results by Upstream Product

	Crude Oil (1)					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**1,607**	2,575	**721**	1,359	**2,328**	3,934
Less: Royalties	**19**	118	**55**	116	**74**	234
	1,588	2,457	**666**	1,243	**2,254**	3,700
Expenses						
Transportation and Blending	**905**	1,118	**111**	180	**1,016**	1,298
Operating	**262**	336	**209**	278	**471**	614
Production and Mineral Taxes	**-**	-	**10**	18	**10**	18
(Gain) Loss on Risk Management	**(106)**	57	**(51)**	32	**(157)**	89
Operating Cash Flow	**527**	946	**387**	735	**914**	1,681

(1) Includes NGLs.

	Natural Gas					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**11**	49	**233**	398	**244**	447
Less: Royalties	**-**	1	**3**	6	**3**	7
	11	48	**230**	392	**241**	440
Expenses						
Transportation and Blending	**1**	1	**9**	9	**10**	10
Operating	**8**	9	**90**	101	**98**	110
Production and Mineral Taxes	**-**	-	**1**	6	**1**	6
(Gain) Loss on Risk Management	**(2)**	-	**(25)**	1	**(27)**	1
Operating Cash Flow	**4**	38	**155**	275	**159**	313

	Other					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**5**	5	**8**	7	**13**	12
Less: Royalties	**-**	-	**-**	-	**-**	-
	5	5	**8**	7	**13**	12
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**2**	4	**2**	2	**4**	6
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**3**	1	**6**	5	**9**	6

	Total Upstream					
	Oil Sands		Conventional		Total	
For the six months ended June 30,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**1,623**	2,629	**962**	1,764	**2,585**	4,393
Less: Royalties	**19**	119	**58**	122	**77**	241
	1,604	2,510	**904**	1,642	**2,508**	4,152
Expenses						
Transportation and Blending	**906**	1,119	**120**	189	**1,026**	1,308
Operating	**272**	349	**301**	381	**573**	730
Production and Mineral Taxes	**-**	-	**11**	24	**11**	24
(Gain) Loss on Risk Management	**(108)**	57	**(76)**	33	**(184)**	90
Operating Cash Flow	**534**	985	**548**	1,015	**1,082**	2,000

F) Geographic Information

For the six months ended June 30,	Canada 2015	Canada 2014	United States 2015	United States 2014	Consolidated 2015	Consolidated 2014
Revenues						
Gross Sales	**3,492**	5,637	**3,452**	5,038	**6,944**	10,675
Less: Royalties	**77**	241	**-**	-	**77**	241
	3,415	5,396	**3,452**	5,038	**6,867**	10,434
Expenses						
Purchased Product	**876**	1,227	**2,764**	4,232	**3,640**	5,459
Transportation and Blending	**1,026**	1,308	**-**	-	**1,026**	1,308
Operating	**584**	743	**322**	347	**906**	1,090
Production and Mineral Taxes	**11**	24	**-**	-	**11**	24
(Gain) Loss on Risk Management	**99**	72	**-**	(2)	**99**	70
	819	2,022	**366**	461	**1,185**	2,483
Depreciation, Depletion and Amortization	**891**	863	**91**	77	**982**	940
Exploration Expense	**21**	1	**-**	-	**21**	1
Segment Income (Loss)	**(93)**	1,158	**275**	384	**182**	1,542

G) Joint Operations

A significant portion of the operating cash flows from the Oil Sands, and Refining and Marketing segments are derived through jointly controlled entities, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), respectively. These joint arrangements, in which Cenovus has a 50 percent ownership interest, are classified as joint operations and, as such, Cenovus recognizes its share of the assets, liabilities, revenues and expenses.

FCCL, which is involved in the development and production of crude oil in Canada, is jointly controlled with ConocoPhillips and operated by Cenovus. WRB has two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with and operated by Phillips 66. Cenovus's share of operating cash flow from FCCL and WRB for the three months ended June 30, 2015 was $286 million and $297 million, respectively (three months ended June 30, 2014 – $538 million and $223 million). Cenovus's share of operating cash flow from FCCL and WRB for the six months ended June 30, 2015 was $420 million and $384 million, respectively (six months ended June 30, 2014 – $956 million and $468 million).

H) Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

By Segment

As at	E&E (1) June 30, 2015	E&E (1) December 31, 2014	PP&E (2) June 30, 2015	PP&E (2) December 31, 2014
Oil Sands	**1,633**	1,540	**8,850**	8,606
Conventional	**64**	85	**4,771**	6,038
Refining and Marketing	**-**	-	**3,837**	3,568
Corporate and Eliminations	**-**	-	**328**	351
Consolidated	**1,697**	1,625	**17,786**	18,563

As at	Goodwill June 30, 2015	Goodwill December 31, 2014	Total Assets June 30, 2015	Total Assets December 31, 2014
Oil Sands	**242**	242	**11,247**	11,024
Conventional	**-**	-	**5,870**	6,211
Refining and Marketing	**-**	-	**5,797**	5,520
Corporate and Eliminations	**-**	-	**2,253**	1,940
Consolidated	**242**	242	**25,167**	24,695

(1) Exploration and evaluation ("E&E") assets.
(2) Property, plant and equipment ("PP&E").

By Geographic Region

	E&E		PP&E	
As at	**June 30, 2015**	December 31, 2014	**June 30, 2015**	December 31, 2014
Canada	**1,697**	1,625	**13,954**	14,999
United States	**-**	-	**3,832**	3,564
Consolidated	**1,697**	1,625	**17,786**	18,563

	Goodwill		Total Assets	
As at	**June 30, 2015**	December 31, 2014	**June 30, 2015**	December 31, 2014
Canada	**242**	242	**20,186**	20,231
United States	**-**	-	**4,981**	4,464
Consolidated	**242**	242	**25,167**	24,695

I) Capital Expenditures [1]

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2015**	2014	**2015**	2014
Capital				
Oil Sands	**260**	471	**674**	998
Conventional	**36**	153	**102**	423
Refining and Marketing	**48**	46	**92**	69
Corporate	**13**	16	**18**	25
	357	686	**886**	1,515
Acquisition Capital				
Oil Sands [2]	**-**	15	**-**	15
Conventional	**-**	1	**-**	2
	357	702	**886**	1,532

(1) Includes expenditures on PP&E and E&E.
(2) 2014 asset acquisition includes the assumption of a decommissioning liability of $10 million.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these interim Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34"), and have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2014, except for income taxes. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. The disclosures provided are incremental to those included with the annual Consolidated Financial Statements. Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2014, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee effective July 29, 2015.

3. RECENT ACCOUNTING PRONOUNCEMENTS

A) New and Amended Accounting Standards and Interpretations Adopted

There were no new or amended accounting standards or interpretations adopted during the six months ended June 30, 2015.

B) New Accounting Standards and Interpretations not yet Adopted

Revenue Recognition

On May 28, 2014, the IASB issued 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.

On July 22, 2015, the IASB announced an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. Early adoption is still permitted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements.

Additional Standards

A description of additional accounting standards and interpretations that will be adopted by the Company in future periods can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2014.

4. FINANCE COSTS

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2015**	2014	**2015**	2014
Interest Expense – Short-Term Borrowings and Long-Term Debt	**79**	70	**159**	141
Interest Expense – Partnership Contribution Payable [(1)]	**-**	-	**-**	22
Unwinding of Discount on Decommissioning Liabilities (Note 15)	**31**	30	**62**	60
Other	**6**	2	**16**	9
	116	102	**237**	232

(1) On March 28, 2014, Cenovus repaid the remaining principal and accrued interest due under the Partnership Contribution Payable.

5. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2015**	2014	**2015**	2014
Unrealized Foreign Exchange (Gain) Loss on Translation of:				
U.S. Dollar Debt Issued From Canada	**(99)**	(177)	**415**	19
Other	**(3)**	(4)	**6**	(57)
Unrealized Foreign Exchange (Gain) Loss	**(102)**	(181)	**421**	(38)
Realized Foreign Exchange (Gain) Loss	**2**	(6)	**(6)**	(2)
	(100)	(187)	**415**	(40)

6. INCOME TAXES

The provision for income taxes is:

For the period ended June 30,	Three Months Ended 2015	2014	Six Months Ended 2015	2014
Current Tax				
Canada	**321**	(10)	**235**	33
United States	**(6)**	3	**(6)**	35
Total Current Tax	**315**	(7)	**229**	68
Deferred Tax	**(261)**	216	**(288)**	252
	54	209	**(59)**	320

On June 29, 2015, the Alberta government enacted a two percent increase in the corporate income tax rate. The rate increase is effective July 1, 2015. As a result, the Company's deferred income tax liability increased by $168 million in the quarter.

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

For the period ended June 30,	Six Months Ended 2015	2014
Earnings (Loss) Before Income Tax	**(601)**	1,182
Canadian Statutory Rate	**26.1%**	25.2%
Expected Income Tax (Recovery)	**(157)**	298
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**4**	25
Non-Deductible Stock-Based Compensation	**5**	10
Non-Taxable Capital Losses	**56**	7
Unrecognized Capital Losses Arising From Unrealized Foreign Exchange	**56**	7
Adjustments Arising From Prior Year Tax Filings	**(11)**	-
Recognition of Capital Losses	**(149)**	(4)
Change in Statutory Rate	**168**	-
Other	**(31)**	(23)
Total Tax	**(59)**	320
Effective Tax Rate	**9.8%**	27.1%

7. PER SHARE AMOUNTS

A) Net Earnings Per Share

For the period ended June 30,	Three Months Ended 2015	2014	Six Months Ended 2015	2014
Net Earnings (Loss) – Basic and Diluted ($ millions)	**126**	615	**(542)**	862
Basic – Weighted Average Number of Shares (millions)	**828.6**	756.9	**803.9**	756.7
Dilutive Effect of Cenovus TSARs (1)	**-**	0.9	**-**	0.9
Dilutive Effect of Cenovus NSRs (2)	**-**	0.2	**-**	-
Diluted – Weighted Average Number of Shares	**828.6**	758.0	**803.9**	757.6
Net Earnings (Loss) Per Common Share ($)				
Basic	**$0.15**	$0.81	**$(0.67)**	$1.14
Diluted	**$0.15**	$0.81	**$(0.67)**	$1.14

(1) Tandem stock appreciation rights ("TSARs").
(2) Net settlement rights ("NSRs").

B) Dividends Per Share

The Company paid dividends of $0.5324 per share or $445 million for the six months ended June 30, 2015 (June 30, 2014 – $403 million, $0.5324 per share), including cash dividends of $263 million (June 30, 2014 – $403 million). The Cenovus Board of Directors declared a third quarter dividend of $0.16 per share, payable on September 30, 2015, to common shareholders of record as of September 15, 2015. While the dividend reinvestment plan ("DRIP") remains in place, the discount has been discontinued.

8. INVENTORIES

As at	**June 30, 2015**	December 31, 2014
Product		
Refining and Marketing	**1,013**	972
Oil Sands	**217**	182
Conventional	**15**	28
Parts and Supplies	**46**	42
	1,291	1,224

As a result of a decline in certain refined product prices, Cenovus recorded a write-down of its refined product inventory of $2 million from cost to net realizable value as at June 30, 2015. As at December 31, 2014, Cenovus recorded a write-down of its product inventory of $131 million.

9. ASSETS AND LIABILITIES HELD FOR SALE

As at	**June 30, 2015**	December 31, 2014
Assets Held for Sale		
Cash and Cash Equivalents	**44**	-
Accounts Receivable	**26**	-
Property, Plant and Equipment	**856**	-
	926	-
Liabilities Related to Assets Held for Sale		
Accounts Payable	**2**	-
	2	-

On June 29, 2015, the Company entered into an agreement with a third party to sell Heritage Royalty Limited Partnership ("HRP"), a wholly-owned subsidiary, for gross cash proceeds of approximately $3.3 billion. HRP holds the Company's royalty business, which consists of approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. Cenovus has entered into lease agreements with HRP on the fee lands from which it currently has working interest production. In addition, HRP has a Gross Overriding Royalty on Cenovus's Pelican Lake heavy oil operation and its enhanced oil recovery project at Weyburn. The transaction is effective April 1, 2015 and closed July 29, 2015.

As at June 30, 2015, the net assets have been classified as assets held for sale and recorded at the lesser of fair value less costs of disposal and their carrying amount, and depletion ceased. These assets and liabilities are reported in the Conventional segment. The after tax gain on the divestiture is expected to be approximately $1.9 billion, which will be recorded in the third quarter.

10. EXPLORATION AND EVALUATION ASSETS

COST	
As at December 31, 2013	1,473
Additions	279
Transfers to PP&E (Note 11)	(53)
Exploration Expense	(86)
Divestitures	(2)
Change in Decommissioning Liabilities	14
As at December 31, 2014	1,625
Additions	94
Transfers to PP&E (Note 11)	(1)
Exploration Expense	(21)
Change in Decommissioning Liabilities	-
As at June 30, 2015	**1,697**

E&E assets consist of the Company's projects which are pending determination of technical feasibility and commercial viability. All of the Company's E&E assets are located within Canada.

Additions to E&E assets for the six months ended June 30, 2015 include $18 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2014 – $51 million). No borrowing costs or costs classified as general and administrative expenses have been capitalized during the six months ended June 30, 2015 (year ended December 31, 2014 – $nil).

For the six months ended June 30, 2015, $1 million of E&E assets were transferred to PP&E following the determination of technical feasibility and commercial viability of the projects (year ended December 31, 2014 – $53 million).

Impairment

The impairment of E&E assets and any subsequent reversal of such impairment losses are recorded in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. For the six months ended June 30, 2015, $21 million of previously capitalized E&E costs related to exploration assets within the Saskatchewan cash-generating unit ("CGU") were deemed not to be technically feasible and commercially viable and were recorded as exploration expense in the Conventional segment.

For the year ended December 31, 2014, $82 million of previously capitalized E&E costs related to exploration assets within the Northern Alberta CGU were deemed not to be technically feasible and commercially viable and were recorded as exploration expense in the Conventional segment. In addition, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense in the Oil Sands segment.

11. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	**Other Upstream**	**Refining Equipment**	**Other (1)**	**Total**
COST					
As at December 31, 2013	29,390	286	3,654	849	34,179
Additions (2)	2,522	43	162	63	2,790
Transfers From E&E Assets (Note 10)	53	-	-	-	53
Transfers to Assets Held for Sale	(55)	-	-	-	(55)
Change in Decommissioning Liabilities	264	-	(3)	-	261
Exchange Rate Movements and Other	1	-	338	-	339
Divestitures	(474)	-	-	(2)	(476)
As at December 31, 2014	31,701	329	4,151	910	37,091
Additions	680	2	91	19	792
Transfers From E&E Assets (Note 10)	1	-	-	-	1
Transfers to Assets Held for Sale (Note 9)	(922)	-	-	-	(922)
Change in Decommissioning Liabilities	(1)	-	-	-	(1)
Exchange Rate Movements and Other	-	-	313	-	313
As at June 30, 2015	**31,459**	**331**	**4,555**	**929**	**37,274**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2013	15,791	193	386	475	16,845
Depreciation, Depletion and Amortization	1,602	40	156	83	1,881
Transfers to Assets Held for Sale	(27)	-	-	-	(27)
Impairment Losses	65	-	-	-	65
Exchange Rate Movements and Other	38	-	42	-	80
Divestitures	(316)	-	-	-	(316)
As at December 31, 2014	17,153	233	584	558	18,528
Depreciation, Depletion and Amortization	824	25	91	42	982
Transfers to Assets Held for Sale (Note 9)	(66)	-	-	-	(66)
Exchange Rate Movements and Other	-	-	44	-	44
As at June 30, 2015	**17,911**	**258**	**719**	**600**	**19,488**
CARRYING VALUE					
As at December 31, 2013	13,599	93	3,268	374	17,334
As at December 31, 2014	14,548	96	3,567	352	18,563
As at June 30, 2015	**13,548**	**73**	**3,836**	**329**	**17,786**

(1) *Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.*
(2) *2014 asset acquisition includes the assumption of a decommissioning liability of $10 million.*

Additions to development and production assets include internal costs directly related to the development and construction of crude oil and natural gas properties of $88 million for the six months ended June 30, 2015 (year ended December 31, 2014 – $216 million). All of the Company's development and production assets are located within Canada. No borrowing costs or costs classified as general and administrative expenses have been capitalized during the six months ended June 30, 2015 (year ended December 31, 2014 – $nil).

PP&E includes the following amounts in respect of assets under construction and are not subject to depreciation, depletion and amortization ("DD&A"):

As at	June 30, 2015	December 31, 2014
Development and Production	519	478
Refining Equipment	211	159
	730	637

Impairment

The impairment of PP&E and any subsequent reversal of such impairment losses are recorded in DD&A in the Consolidated Statements of Earnings and Comprehensive Income. There was no impairment of PP&E for the six months ended June 30, 2015 (year ended December 31, 2014 – $65 million).

12. ACQUISITION

On June 4, 2015, the Company announced an agreement to purchase a crude-by-rail trans-loading facility for $75 million plus closing adjustments. The transaction is expected to close in late August 2015.

13. DIVESTITURE

In the first quarter of 2015, the Company divested an office building, recording a gain of $16 million.

In the second quarter of 2014, the Company completed the sale of certain Bakken properties to a third party for net proceeds of $35 million, resulting in a gain of $16 million. The Company also completed the sale of certain non-core properties and recorded a total gain of $4 million. These assets, related liabilities and results of operations were reported in the Conventional segment.

14. LONG-TERM DEBT

As at	US$ Principal	June 30, 2015	December 31, 2014
Revolving Term Debt (1)	-	-	-
U.S. Dollar Denominated Unsecured Notes	4,750	5,925	5,510
Total Debt Principal		5,925	5,510
Debt Discounts and Transaction Costs		(50)	(52)
		5,875	5,458

(1) Revolving term debt may include bankers' acceptances, LIBOR loans, prime rate loans and U.S. base rate loans.

During the second quarter, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2019. In addition, a new $1.0 billion tranche was established under the same facility, maturing on November 30, 2017. As at June 30, 2015, the Company had $4.0 billion available on its committed credit facility.

As at June 30, 2015, the Company is in compliance with all of the terms of its debt agreements.

15. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the expected future costs associated with the retirement of upstream crude oil and natural gas assets and refining facilities. The aggregate carrying amount of the obligation is:

As at	June 30, 2015	December 31, 2014
Decommissioning Liabilities, Beginning of Year	2,616	2,370
Liabilities Incurred	7	48
Liabilities Settled	(48)	(93)
Liabilities Divested	-	(60)
Transfers and Reclassifications	-	(9)
Change in Estimated Future Cash Flows	(8)	115
Change in Discount Rate	-	122
Unwinding of Discount on Decommissioning Liabilities	62	120
Foreign Currency Translation	3	3
Decommissioning Liabilities, End of Period	2,632	2,616

The undiscounted amount of estimated future cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 4.9 percent as at June 30, 2015 (December 31, 2014 – 4.9 percent).

16. SHARE CAPITAL

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

B) Issued and Outstanding

	June 30, 2015		December 31, 2014	
As at	Number of Common Shares (Thousands)	Amount	Number of Common Shares (Thousands)	Amount
Outstanding, Beginning of Year	757,103	3,889	756,046	3,857
Common Shares Issued, Net of Issuance Costs	67,500	1,463	-	-
Common Shares Issued Pursuant to Dividend Reinvestment Plan	8,687	182	-	-
Common Shares Issued Under Stock Option Plans	-	-	1,057	32
Outstanding, End of Period	833,290	5,534	757,103	3,889

On March 3, 2015, Cenovus issued 67.5 million common shares at a price of $22.25 per common share. The Company intends to use the net proceeds to partially fund its capital expenditure program for 2015 and for general corporate purposes.

The Company has a DRIP, whereby holders of common shares may reinvest all or a portion of the cash dividends payable on their common shares in additional common shares. At the discretion of the Company, the additional common shares may be issued from treasury of the Company or purchased on the market. For the six months ended June 30, 2015, the Company issued 8.7 million common shares from treasury under the DRIP.

There were no preferred shares outstanding as at June 30, 2015 (December 31, 2014 – nil).

As at June 30, 2015, there were 10 million (December 31, 2014 – 13 million) common shares available for future issuance under stock option plans.

17. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at June 30, 2015	**Defined Benefit Plan**	**Foreign Currency Translation**	**Available for Sale Investments**	**Total**
Balance, Beginning of Year	**(30)**	**427**	**10**	**407**
Other Comprehensive Income (Loss), Before Tax	**11**	**218**	**-**	**229**
Income Tax	**(2)**	**-**	**-**	**(2)**
Balance, End of Period	**(21)**	**645**	**10**	**634**

As at June 30, 2014	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Investments	Total
Balance, Beginning of Year	(12)	212	10	210
Other Comprehensive Income (Loss), Before Tax	(7)	(41)	-	(48)
Income Tax	2	-	-	2
Balance, End of Period	(17)	171	10	164

18. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Options issued under the plan have associated TSARs or NSRs.

The following table is a summary of the options outstanding at the end of the period:

As at June 30, 2015	**Issued**	**Term** (Years)	**Weighted Average Remaining Contractual Life** (Years)	**Weighted Average Exercise Price** ($)	**Closing Share Price** ($)	**Number of Units Outstanding** (Thousands)
NSRs	On or After February 24, 2011	**7**	**4.83**	**31.66**	**19.97**	**43,670**
TSARs	On or After February 17, 2010	**7**	**1.70**	**26.72**	**19.97**	**3,743**

NSRs

The weighted average unit fair value of NSRs granted during the six months ended June 30, 2015 was $3.58 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model.

The following table summarizes information related to the NSRs:

As at June 30, 2015	**Number of NSRs** (Thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**40,549**	**32.63**
Granted	**4,100**	**22.26**
Exercised	**-**	**-**
Forfeited	**(979)**	**32.44**
Outstanding, End of Period	**43,670**	**31.66**
Exercisable, End of Period	**23,570**	**34.55**

TSARs

The Company has recorded a liability of $3 million as at June 30, 2015 (December 31, 2014 – $8 million) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. The intrinsic value of vested TSARs held by Cenovus employees as at June 30, 2015 was $nil (December 31, 2014 – $nil).

The following table summarizes information related to the TSARs held by Cenovus employees:

As at June 30, 2015	Number of TSARs (Thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	3,862	26.72
Exercised for Cash Payment	-	-
Exercised as Options for Common Shares	-	-
Forfeited	(48)	27.86
Expired	(71)	25.80
Outstanding, End of Period	3,743	26.72
Exercisable, End of Period	3,743	26.72

B) Performance Share Units

The Company has recorded a liability of $65 million as at June 30, 2015 (December 31, 2014 – $109 million) in the Consolidated Balance Sheets for performance share units ("PSUs") based on the market value of Cenovus's common shares as at June 30, 2015. As PSUs are paid out upon vesting, the intrinsic value of vested PSUs was $nil as at June 30, 2015 and December 31, 2014.

The following table summarizes the information related to the PSUs held by Cenovus employees:

As at June 30, 2015	Number of PSUs (Thousands)
Outstanding, Beginning of Year	7,099
Granted	2,904
Vested and Paid Out	(1,436)
Cancelled	(1,115)
Units in Lieu of Dividends	158
Outstanding, End of Period	7,610

C) Restricted Share Units

Cenovus has granted restricted share units ("RSUs") to certain employees under its Restricted Share Unit Plan for Employees. RSUs are whole share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. RSUs vest after three years.

RSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as compensation costs over the vesting period. Fluctuations in the fair value are recognized as compensation costs in the period they occur.

The Company has recorded a liability of $7 million as at June 30, 2015 (December 31, 2014 – $1 million) in the Consolidated Balance Sheets for RSUs based on the market value of Cenovus's common shares as at June 30, 2015. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at June 30, 2015 and December 31, 2014.

The following table summarizes the information related to the RSUs held by Cenovus employees:

As at June 30, 2015	Number of RSUs (Thousands)
Outstanding, Beginning of Year	93
Granted	2,328
Vested and Paid Out	(22)
Cancelled	(20)
Units in Lieu of Dividends	62
Outstanding, End of Period	2,441

D) Deferred Share Units

The Company has recorded a liability of $28 million as at June 30, 2015 (December 31, 2014 – $31 million) in the Consolidated Balance Sheets for deferred share units ("DSUs") based on the market value of Cenovus's common shares as at June 30, 2015. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees:

As at June 30, 2015	**Number of DSUs** (Thousands)
Outstanding, Beginning of Year	**1,297**
Granted to Directors	**63**
Granted From Annual Bonus Awards	**25**
Units in Lieu of Dividends	**36**
Redeemed	**(5)**
Outstanding, End of Period	**1,416**

E) Total Stock-Based Compensation Expense (Recovery)

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans within operating, and general and administrative expenses in the Consolidated Statements of Earnings and Comprehensive Income:

	Three Months Ended		**Six Months Ended**	
For the period ended June 30,	**2015**	2014	**2015**	2014
NSRs	**3**	11	**14**	24
TSARs	**-**	4	**(3)**	4
PSUs	**9**	15	**(7)**	47
RSUs	**-**	-	**3**	-
DSUs	**(1)**	3	**(3)**	7
Stock-Based Compensation Expense (Recovery)	**11**	33	**4**	82

19. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings, and the current and long-term portions of long-term debt. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA"). These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Cenovus continues to target a Debt to Capitalization ratio of between 30 and 40 percent over the long-term.

As at	**June 30, 2015**	December 31, 2014
Long-Term Debt	**5,875**	5,458
Shareholders' Equity	**11,095**	10,186
Capitalization	**16,970**	15,644
Debt to Capitalization	**35%**	35%

Cenovus continues to target a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times over the long term. As at June 30, 2015, the Company's Debt to Adjusted EBITDA ratio was above the target of 2.0 times; however, Cenovus believes it will return to the target range.

As at	June 30, 2015	December 31, 2014
Debt	**5,875**	5,458
Adjusted EBITDA (1)		
Net Earnings (Loss)	**(660)**	744
Add (Deduct):		
Finance Costs	**450**	445
Interest Income	**(20)**	(33)
Income Tax Expense (Recovery)	**72**	451
Depreciation, Depletion and Amortization	**1,988**	1,946
Goodwill Impairment	**497**	497
E&E Impairment	**106**	86
Unrealized (Gain) Loss on Risk Management	**(285)**	(596)
Foreign Exchange (Gain) Loss, Net	**866**	411
(Gain) Loss on Divestitures of Assets	**(152)**	(156)
Other (Income) Loss, Net	**-**	(4)
	2,862	3,791
Debt to Adjusted EBITDA	**2.1x**	1.4x

(1) *Calculated on a trailing twelve-month basis.*

Cenovus will maintain a high level of capital discipline and manage its capital structure to ensure sufficient liquidity through all stages of the economic cycle. To manage its capital structure, Cenovus may adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facilities or repay existing debt. It is Cenovus's intention to maintain investment grade credit ratings.

During the second quarter, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2019. In addition, a new $1.0 billion tranche was established under the same facility, maturing on November 30, 2017. As at June 30, 2015, Cenovus had $4.0 billion available on its committed credit facility. In addition, Cenovus had in place a $1.5 billion Canadian base shelf prospectus and a US$2.0 billion U.S. base shelf prospectus, the availability of which are dependent on market conditions.

As at June 30, 2015, Cenovus is in compliance with all of the terms of its debt agreements.

20. FINANCIAL INSTRUMENTS

Cenovus's consolidated financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, risk management assets and liabilities, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of those instruments.

The fair values of long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on period-end trading prices of long-term borrowings on the secondary market (Level 2). As at June 30, 2015, the carrying value of Cenovus's long-term debt was $5,875 million and the fair value was $6,131 million (December 31, 2014 carrying value – $5,458 million, fair value – $5,726 million).

Available for sale financial assets comprise private equity investments. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available. When fair value cannot be reliably measured, these assets are carried at cost. The following table provides a reconciliation of changes in the fair value of available for sale financial assets:

As at	June 30, 2015	December 31, 2014
Fair Value, Beginning of Year	32	32
Acquisition of Investments	2	4
Reclassification of Equity Investments	-	(4)
Fair Value, End of Period	34	32

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, natural gas and power purchase contracts. Crude oil and natural gas contracts are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The forward prices used in the determination of the fair value of the power purchase contracts as at June 30, 2015 range from $40.50 to $92.00 per Megawatt Hour.

Summary of Unrealized Risk Management Positions

	June 30, 2015			December 31, 2014		
	Risk Management			Risk Management		
As at	Asset	Liability	Net	Asset	Liability	Net
Commodity Prices						
Crude Oil	158	15	143	423	7	416
Natural Gas	29	-	29	55	-	55
Power	-	5	(5)	-	9	(9)
Total Fair Value	187	20	167	478	16	462

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at	June 30, 2015	December 31, 2014
Prices Sourced From Observable Data or Market Corroboration (Level 2)	172	471
Prices Determined From Unobservable Inputs (Level 3)	(5)	(9)
	167	462

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data. Prices determined from unobservable inputs refers to the fair value of contracts valued using data that is both unobservable and significant to the overall fair value measurement.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities from January 1 to June 30:

	2015	2014
Fair Value of Contracts, Beginning of Year	462	(129)
Fair Value of Contracts Realized During the Period (1)	(197)	85
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Period (2)	(99)	(70)
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	1	-
Fair Value of Contracts, End of Period	167	(114)

(1) Includes a realized loss of $3 million related to the power contracts (2014 – $2 million loss).
(2) Includes an increase of $1 million related to the power contracts (2014 – $1 million decrease).

C) Earnings Impact of (Gains) Losses From Risk Management Positions

	Three Months Ended		Six Months Ended	
For the period ended June 30,	**2015**	2014	**2015**	2014
Realized (Gain) Loss (1)	**(46)**	55	**(197)**	85
Unrealized (Gain) Loss (2)	**151**	11	**296**	(15)
(Gain) Loss on Risk Management	**105**	66	**99**	70

(1) Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.
(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

21. RISK MANAGEMENT

The Company is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk. A description of the nature and extent of risks arising from the Company's financial assets and liabilities can be found in the notes to the annual Consolidated Financial Statements as at December 31, 2014. The Company's exposure to these risks has not changed significantly since December 31, 2014.

Net Fair Value of Commodity Price Positions

As at June 30, 2015	Notional Volumes	Term	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	18,000 bbls/d	January – December 2015	$113.75/bbl	**107**
Brent Fixed Price	25,000 bbls/d	July – September 2015	$80.76/bbl	**1**
Brent Fixed Price	25,000 bbls/d	July – September 2015	US$60.41/bbl	**(12)**
Brent Fixed Price	8,000 bbls/d	October – December 2015	$82.59/bbl	**-**
Brent Fixed Price	18,000 bbls/d	October – December 2015	US$67.22/bbl	**3**
Brent Fixed Price	6,000 bbls/d	January – June 2016	$84.44/bbl	**-**
Brent Fixed Price	9,000 bbls/d	January – June 2016	US$69.63/bbl	**4**
Brent Fixed Price	10,000 bbls/d	January – December 2016	US$66.93/bbl	**(5)**
Brent Collars	10,000 bbls/d	January – December 2015	$105.25 – $123.57/bbl	**45**
Crude Oil Fair Value Position				**143**
Natural Gas Contracts				
Fixed Price Contracts				
AECO Fixed Price	149 MMcf/d	January – December 2015	$3.86/Mcf	**29**
Natural Gas Fair Value Position				**29**
Power Purchase Contracts				
Power Fair Value Position				**(5)**

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

Risk Management Positions in Place as at June 30, 2015

Commodity	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(249)	251
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	-	-
Natural Gas Commodity Price	± US$1 per Mcf Applied to NYMEX and AECO Natural Gas Hedges	(38)	38
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	19	(19)

22. COMMITMENTS AND CONTINGENCIES

A) Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, the Company has commitments related to its risk management program and an obligation to fund its defined benefit pension and other post-employment benefit plans. Additional information related to the Company's commitments can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2014. The Company did not enter into any new material contracts for the six months ended June 30, 2015.

B) Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes it has made adequate provisions for such legal claims. There are no individually or collectively significant claims.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)

Revenues	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Gross Sales									
Upstream	**2,585**	**1,410**	1,175	8,261	1,721	2,147	**4,393**	2,295	2,098
Refining and Marketing	**4,533**	**2,437**	2,096	12,658	2,773	3,144	**6,741**	3,483	3,258
Corporate and Eliminations	**(174)**	**(68)**	(106)	(812)	(156)	(197)	**(459)**	(218)	(241)
Less: Royalties	**77**	**53**	24	465	100	124	**241**	138	103
Revenues	**6,867**	**3,726**	3,141	19,642	4,238	4,970	**10,434**	5,422	5,012

Operating Cash Flow	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Crude Oil and Natural Gas Liquids									
Foster Creek	**213**	**129**	84	965	228	297	**440**	227	213
Christina Lake	**314**	**198**	116	1,051	237	308	**506**	291	215
Conventional	**387**	**221**	166	1,360	273	352	**735**	388	347
Natural Gas	**159**	**78**	81	553	111	129	**313**	162	151
Other Upstream Operations	**9**	**2**	7	18	12	-	**6**	8	(2)
	1,082	**628**	454	3,947	861	1,086	**2,000**	1,076	924
Refining and Marketing	**395**	**300**	95	211	(322)	68	**465**	220	245
Operating Cash Flow (1)	**1,477**	**928**	549	4,158	539	1,154	**2,465**	1,296	1,169

Cash Flow	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Cash from Operating Activities	**610**	**335**	275	3,526	868	1,092	**1,566**	1,109	457
Deduct (Add Back):									
Net Change in Other Assets and Liabilities	**(68)**	**(14)**	(54)	(135)	(38)	(28)	**(69)**	(27)	(42)
Net Change in Non-Cash Working Capital	**(294)**	**(128)**	(166)	182	505	135	**(458)**	(53)	(405)
Cash Flow (2)	**972**	**477**	495	3,479	401	985	**2,093**	1,189	904
Per Share - Basic	**1.21**	**0.58**	0.64	4.60	0.53	1.30	**2.77**	1.57	1.20
- Diluted	**1.21**	**0.58**	0.64	4.59	0.53	1.30	**2.76**	1.57	1.19

Earnings	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Operating Earnings (Loss) (3)	**63**	**151**	(88)	633	(590)	372	**851**	473	378
Per Share - Diluted	**0.08**	**0.18**	(0.11)	0.84	(0.78)	0.49	**1.12**	0.62	0.50
Net Earnings (Loss)	**(542)**	**126**	(668)	744	(472)	354	**862**	615	247
Per Share - Basic	**(0.67)**	**0.15**	(0.86)	0.98	(0.62)	0.47	**1.14**	0.81	0.33
- Diluted	**(0.67)**	**0.15**	(0.86)	0.98	(0.62)	0.47	**1.14**	0.81	0.33

Tax & Exchange Rates	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Effective Tax Rates Using:									
Net Earnings (4)	**9.8%**			37.7%					
Operating Earnings, Excluding Divestitures	**33.0%**			29.7%					
Canadian Statutory Rate (4)	**26.1%**			25.2%					
U.S. Statutory Rate	**38.1%**			38.1%					
Foreign Exchange Rates *(US$ per C$1)*									
Average	**0.810**	**0.813**	0.806	0.905	0.881	0.918	**0.912**	0.917	0.906
Period End	**0.802**	**0.802**	0.789	0.862	0.862	0.892	**0.937**	0.937	0.905

(1) Operating Cash Flow is a non-GAAP measure 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.

(2) Cash Flow is a non-GAAP measure defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital, both of which are defined on the Consolidated Statement of Cash Flows.

(3) Operating Earnings (Loss) 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 (Loss) is defined as Earnings (Loss) 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, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates.

(4) On June 29, 2015, the Alberta government enacted a two percent increase in the corporate income tax rate. The rate increase is effective July 1, 2015.

Financial Metrics (Non-GAAP measures)	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Debt to Capitalization (1) (2)	**35%**	**35%**	35%	35%	35%	33%	**33%**	33%	36%
Net Debt to Capitalization (3) (4)	**28%**	**28%**	27%	31%	31%	28%	**30%**	30%	32%
Debt to Adjusted EBITDA (2) (5)	**2.1x**	**2.1x**	1.9x	1.4x	1.4x	1.3x	**1.2x**	1.2x	1.4x
Net Debt to Adjusted EBITDA (3) (5)	**1.5x**	**1.5x**	1.3x	1.2x	1.2x	1.0x	**1.1x**	1.1x	1.2x
Return on Capital Employed (6)	**(3)%**	**(3)%**	0%	6%	6%	9%	**9%**	9%	7%
Return on Common Equity (7)	**(6)%**	**(6)%**	(2)%	7%	7%	11%	**12%**	12%	7%

(1) Capitalization is a non-GAAP measure defined as debt plus shareholders' equity.

(2) Debt includes the Company's short-term borrowings and the current and long-term portions of long-term debt.

(3) Net debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents.

(4) Net debt to capitalization is defined as net debt divided by net debt plus shareholders' equity.

(5) Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, 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 twelve-month basis.

(6) Return on capital employed is calculated, on a trailing twelve-month basis, as net earnings before after-tax interest divided by average shareholders' equity plus average debt.

(7) Return on common equity is calculated, on a trailing twelve-month basis, as net earnings divided by average shareholders' equity.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Common Share Information	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Common Shares Outstanding *(millions)*									
Period End	**833.3**	**833.3**	828.5	757.1	757.1	757.1	**757.0**	757.0	756.9
Average - Basic	**803.9**	**828.6**	778.9	756.9	757.1	757.1	**756.7**	756.9	756.4
Average - Diluted	**803.9**	**828.6**	778.9	757.6	757.1	758.8	**757.6**	758.0	757.3
Price Range *($ per share)*									
TSX - C$									
High	**26.42**	**24.28**	26.42	34.79	30.13	34.79	**34.70**	34.70	32.02
Low	**19.53**	**19.53**	20.45	18.72	18.72	29.77	**28.25**	30.80	28.25
Close	**19.98**	**19.98**	21.35	23.97	23.97	30.13	**34.59**	34.59	31.97
NYSE - US$									
High	**21.12**	**19.72**	21.12	32.64	26.89	32.64	**32.44**	32.44	28.96
Low	**15.69**	**15.69**	16.29	16.11	16.11	26.57	**25.52**	28.35	25.52
Close	**16.01**	**16.01**	16.88	20.62	20.62	26.88	**32.37**	32.37	28.96
Dividends *($ per share)*	**0.5324**	**0.2662**	0.2662	1.0648	0.2662	0.2662	**0.5324**	0.2662	0.2662
Share Volume Traded *(millions)*	**830.9**	**388.7**	442.1	803.8	333.1	147.7	**322.9**	152.7	170.3

Net Capital Investment	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Capital Investment *($ millions)*									
Oil Sands									
Foster Creek	**222**	**73**	149	796	159	207	**430**	209	221
Christina Lake	**368**	**161**	207	794	231	198	**365**	183	182
Total	**590**	**234**	356	1,590	390	405	**795**	392	403
Other Oil Sands	**84**	**26**	58	396	104	89	**203**	79	124
	674	**260**	414	1,986	494	494	**998**	471	527
Conventional	**102**	**36**	66	840	219	198	**423**	153	270
Refining and Marketing	**92**	**48**	44	163	52	42	**69**	46	23
Corporate	**18**	**13**	5	62	21	16	**25**	16	9
Capital Investment	**886**	**357**	529	3,051	786	750	**1,515**	686	829
Acquisitions [1]	**-**	**-**	-	18	1	-	**17**	16	1
Divestitures	**(16)**	**-**	(16)	(277)	(1)	(235)	**(41)**	(39)	(2)
Net Acquisition and Divestiture Activity	**(16)**	**-**	(16)	(259)	-	(235)	**(24)**	(23)	(1)
Net Capital Investment	**870**	**357**	513	2,792	786	515	**1,491**	663	828

(1) Q2 2014 asset acquisition includes the assumption of a decommissioning liability of $10 million.

Operating Statistics - Before Royalties

Upstream Production Volumes	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*									
Oil Sands									
Foster Creek	**63,106**	**58,363**	67,901	59,172	68,377	56,631	**55,785**	56,852	54,706
Christina Lake	**74,410**	**72,371**	76,471	69,023	73,836	68,458	**66,863**	67,975	65,738
	137,516	**130,734**	144,372	128,195	142,213	125,089	**122,648**	124,827	120,444
Conventional									
Heavy Oil	**36,624**	**36,099**	37,155	39,546	38,021	39,096	**40,550**	40,304	40,799
Light and Medium Oil	**33,463**	**31,809**	35,135	34,531	34,661	33,548	**34,966**	35,329	34,598
Natural Gas Liquids [1]	**1,335**	**1,312**	1,358	1,221	1,282	1,356	**1,121**	1,228	1,013
	71,422	**69,220**	73,648	75,298	73,964	74,000	**76,637**	76,861	76,410
Total Crude Oil and Natural Gas Liquids	**208,938**	**199,954**	218,020	203,493	216,177	199,089	**199,285**	201,688	196,854
Natural Gas *(MMcf/d)*									
Oil Sands	**20**	**21**	20	22	22	23	**21**	23	19
Conventional	**436**	**429**	442	466	457	466	**471**	484	457
Total Natural Gas	**456**	**450**	462	488	479	489	**492**	507	476
Total Production *(BOE/d)*	**284,938**	**274,954**	295,020	284,826	296,010	280,589	**281,285**	286,188	276,187

(1) Natural gas liquids include condensate volumes.

Average Royalty Rates *(Excluding Impact of Realized Gain (Loss) on Risk Management)*	2015 Year to Date	2015 Q2	2015 Q1	2014 Year	2014 Q4	2014 Q3	2014 Q2 Year to Date	2014 Q2	2014 Q1
Oil Sands									
Foster Creek [1]	**2.8%**	**5.0%**	(1.2)%	8.8%	11.2%	7.2%	**8.7%**	9.3%	8.1%
Christina Lake	**2.7%**	**2.5%**	3.1%	7.5%	7.2%	7.9%	**7.4%**	7.7%	7.1%
Conventional									
Pelican Lake	**10.9%**	**14.3%**	6.0%	7.5%	8.4%	7.1%	**7.5%**	8.0%	6.9%
Weyburn	**17.6%**	**18.4%**	16.5%	21.9%	19.0%	24.0%	**22.0%**	24.4%	19.4%
Other	**2.2%**	**1.2%**	3.5%	5.9%	6.7%	6.5%	**5.2%**	5.5%	4.9%
Natural Gas Liquids	**2.2%**	**2.2%**	2.3%	2.1%	2.6%	1.6%	**2.2%**	2.2%	2.2%
Natural Gas	**1.4%**	**1.2%**	1.6%	1.9%	2.5%	2.0%	**1.7%**	2.0%	1.4%

(1) In Q1 2015, regulatory approval was received to include certain capital costs incurred in previous years in the royalty calculation which has resulted in a negative rate. Excluding the credit, the Q1 2015 and year-to-date royalty rate would have been 5.9 percent and 5.0 percent, respectively.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Refining	2015			2014					
	Year to Date	**Q2**	Q1	Year	Q4	Q3	**Q2 Year to Date**	Q2	Q1
Refinery Operations [1]									
Crude Oil Capacity *(Mbbls/d)*	**460**	**460**	460	460	460	460	**460**	460	460
Crude Oil Runs *(Mbbls/d)*	**440**	**441**	439	423	420	407	**433**	466	400
Heavy Oil	**210**	**200**	220	199	179	201	**208**	221	195
Light/Medium	**230**	**241**	219	224	241	206	**225**	245	205
Crude Utilization	**96%**	**96%**	95%	92%	91%	88%	**94%**	101%	87%
Refined Products *(Mbbls/d)*	**465**	**462**	469	445	442	429	**458**	489	420

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

Selected Average Benchmark Prices	2015			2014					
	Year to Date	**Q2**	Q1	Year	Q4	Q3	**Q2 Year to Date**	Q2	Q1
Crude Oil Prices *(US$/bbl)*									
Brent	**59.33**	**63.50**	55.17	99.51	76.98	103.39	**108.83**	109.77	107.90
West Texas Intermediate ("WTI")	**53.29**	**57.94**	48.63	93.00	73.15	97.17	**100.84**	102.99	98.68
Differential Brent - WTI	**6.04**	**5.56**	6.54	6.51	3.83	6.22	**7.99**	6.78	9.22
Western Canadian Select ("WCS")	**40.13**	**46.35**	33.90	73.60	58.91	76.99	**79.25**	82.95	75.55
Differential WTI - WCS	**13.16**	**11.59**	14.73	19.40	14.24	20.18	**21.59**	20.04	23.13
Condensate (C5 @ Edmonton)	**51.78**	**57.94**	45.62	92.95	70.57	93.45	**103.90**	105.15	102.64
Differential WTI - Condensate (Premium)/Discount	**1.51**	**-**	3.01	0.05	2.58	3.72	**(3.06)**	(2.16)	(3.96)
Refining Margins 3-2-1 Crack Spreads [1] *(US$/bbl)*									
Chicago	**18.65**	**20.77**	16.53	17.61	14.60	17.57	**19.13**	19.72	18.55
Group 3	**18.40**	**19.34**	17.46	16.27	13.28	16.65	**17.58**	17.75	17.41
Natural Gas Prices									
AECO *(C$/Mcf)*	**2.81**	**2.67**	2.95	4.42	4.01	4.22	**4.72**	4.67	4.76
NYMEX *(US$/Mcf)*	**2.81**	**2.64**	2.98	4.42	4.00	4.06	**4.80**	4.67	4.94
Differential NYMEX - AECO *(US$/Mcf)*	**0.53**	**0.50**	0.57	0.40	0.44	0.16	**0.50**	0.40	0.60

[1] The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and on a last in, first out accounting basis ("LIFO").

Per-unit Results
(Excluding Impact of Realized Gain (Loss) on Risk Management)

	2015			2014					
	Year to Date	**Q2**	Q1	Year	Q4	Q3	**Q2 Year to Date**	Q2	Q1
Heavy Oil - Foster Creek [1] [2] *($/bbl)*									
Price	**38.53**	**48.25**	29.42	69.43	51.95	76.82	**75.62**	79.77	71.44
Royalties	**0.82**	**1.97**	(0.25)	5.95	5.67	5.40	**6.43**	7.14	5.71
Transportation and Blending	**9.22**	**9.04**	9.39	1.98	1.85	2.17	**1.94**	3.10	0.78
Operating	**13.99**	**13.47**	14.48	16.55	13.65	14.79	**19.24**	19.38	19.09
Netback	**14.50**	**23.77**	5.80	44.95	30.78	54.46	**48.01**	50.15	45.86
Heavy Oil - Christina Lake [1] [2] *($/bbl)*									
Price	**32.71**	**43.36**	23.30	61.57	47.21	67.62	**66.18**	72.25	59.89
Royalties	**0.79**	**0.99**	0.61	4.40	3.14	5.07	**4.72**	5.37	4.04
Transportation and Blending	**4.22**	**4.29**	4.17	3.53	4.14	3.75	**3.08**	3.14	3.02
Operating	**8.26**	**8.32**	8.22	11.20	9.31	10.40	**12.68**	12.08	13.30
Netback	**19.44**	**29.76**	10.30	42.44	30.62	48.40	**45.70**	51.66	39.53
Total Heavy Oil - Oil Sands [1] [2] *($/bbl)*									
Price	**35.35**	**45.61**	26.04	65.18	49.44	71.82	**70.48**	75.65	65.19
Royalties	**0.80**	**1.44**	0.22	5.11	4.33	5.22	**5.50**	6.17	4.80
Transportation and Blending	**6.49**	**6.48**	6.50	2.82	3.06	3.03	**2.56**	3.12	1.99
Operating	**10.86**	**10.74**	10.97	13.66	11.35	12.41	**15.67**	15.38	15.96
Netback	**17.20**	**26.95**	8.35	43.59	30.70	51.16	**46.75**	50.98	42.44
Heavy Oil - Conventional [1] [2] *($/bbl)*									
Price	**44.24**	**52.63**	35.85	76.25	60.25	81.30	**80.93**	83.29	78.52
Royalties	**3.84**	**5.34**	2.34	7.09	6.85	7.72	**6.90**	7.76	6.01
Transportation and Blending	**3.25**	**3.09**	3.42	3.29	3.22	3.40	**3.27**	3.44	3.09
Operating	**16.42**	**15.62**	17.21	20.74	18.24	20.02	**22.18**	20.66	23.73
Production and Mineral Taxes	**0.05**	**0.08**	0.02	0.18	0.03	0.24	**0.23**	0.32	0.13
Netback	**20.68**	**28.50**	12.86	44.95	31.91	49.92	**48.35**	51.11	45.56
Total Heavy Oil [1] [2] *($/bbl)*									
Price	**37.34**	**47.24**	28.15	67.83	51.74	73.99	**73.19**	77.63	68.64
Royalties	**1.48**	**2.35**	0.68	5.59	4.87	5.79	**5.86**	6.58	5.12
Transportation and Blending	**5.77**	**5.69**	5.83	2.93	3.09	3.11	**2.74**	3.20	2.28
Operating	**12.10**	**11.87**	12.32	15.35	12.82	14.15	**17.35**	16.75	17.97
Production and Mineral Taxes	**0.01**	**0.02**	-	0.04	0.01	0.05	**0.06**	0.08	0.03
Netback	**17.98**	**27.31**	9.32	43.92	30.95	50.89	**47.18**	51.02	43.24
Light and Medium Oil *($/bbl)*									
Price	**53.24**	**61.66**	45.81	88.30	71.10	89.85	**96.27**	98.27	94.18
Royalties	**4.55**	**5.67**	3.56	9.15	6.12	10.36	**10.11**	11.37	8.78
Transportation and Blending	**2.97**	**3.06**	2.88	3.34	2.89	3.06	**3.70**	3.31	4.11
Operating	**16.04**	**16.19**	15.91	17.28	15.84	17.40	**17.95**	17.45	18.47
Production and Mineral Taxes	**1.59**	**1.95**	1.28	2.70	2.59	2.99	**2.61**	2.97	2.23
Netback	**28.09**	**34.79**	22.18	55.83	43.66	56.04	**61.90**	63.17	60.59

[1] The netbacks do not reflect non-cash write-downs of product inventory.
[2] Heavy oil price, and transportation and blending costs exclude the costs of purchased condensate, which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate is as follows:

Cost of Condensate per Barrel of Unblended Crude Oil *($/bbl)*									
Foster Creek	**30.21**	**29.82**	30.57	42.01	35.45	38.50	**47.81**	47.28	48.35
Christina Lake	**32.21**	**32.90**	31.60	45.45	38.23	42.57	**51.02**	49.30	52.81
Heavy Oil - Oil Sands	**31.30**	**31.48**	31.14	43.87	36.92	40.71	**49.56**	48.39	50.77
Heavy Oil - Conventional	**11.96**	**12.42**	11.50	15.71	13.98	13.25	**17.63**	17.70	17.56
Total Heavy Oil	**26.98**	**27.06**	26.91	37.13	32.04	34.42	**41.30**	40.44	42.17

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results

(Excluding Impact of Realized Gain (Loss) on Risk Management)

	2015			2014					
	Year to Date	Q2	Q1	Year	Q4	Q3	Q2 Year to Date	Q2	Q1
Total Crude Oil [1] *($/bbl)*									
Price	39.93	49.55	31.09	71.39	55.05	76.64	77.31	81.35	73.15
Royalties	1.98	2.88	1.16	6.21	5.08	6.56	6.62	7.45	5.76
Transportation and Blending	5.31	5.27	5.34	3.00	3.06	3.10	2.91	3.22	2.60
Operating	12.74	12.56	12.91	15.69	13.34	14.70	17.46	16.87	18.06
Production and Mineral Taxes	0.27	0.33	0.22	0.50	0.45	0.54	0.51	0.60	0.42
Netback	19.63	28.51	11.46	45.99	33.12	51.74	49.81	53.21	46.31
Natural Gas Liquids *($/bbl)*									
Price	34.01	39.64	28.51	65.55	50.82	66.70	73.41	78.38	67.31
Royalties	0.76	0.87	0.66	1.38	1.34	1.07	1.60	1.70	1.48
Netback	33.25	38.77	27.85	64.17	49.48	65.63	71.81	76.68	65.83
Total Liquids [1] *($/bbl)*									
Price	39.90	49.48	31.08	71.35	55.02	76.57	77.29	81.33	73.12
Royalties	1.97	2.86	1.16	6.18	5.06	6.52	6.59	7.41	5.74
Transportation and Blending	5.27	5.24	5.31	2.98	3.04	3.08	2.90	3.20	2.59
Operating	12.66	12.48	12.83	15.59	13.25	14.60	17.36	16.77	17.96
Production and Mineral Taxes	0.27	0.33	0.22	0.50	0.44	0.54	0.51	0.60	0.42
Netback	19.73	28.57	11.56	46.10	33.23	51.83	49.93	53.35	46.41
Total Natural Gas *($/Mcf)*									
Price	2.94	2.82	3.05	4.37	3.89	4.22	4.68	4.87	4.47
Royalties	0.04	0.03	0.05	0.08	0.09	0.08	0.08	0.09	0.06
Transportation and Blending	0.11	0.10	0.12	0.12	0.13	0.11	0.11	0.11	0.11
Operating	1.20	1.15	1.26	1.23	1.21	1.24	1.24	1.23	1.26
Production and Mineral Taxes	0.01	0.02	0.01	0.05	0.03	0.05	0.06	0.13	(0.01)
Netback	1.58	1.52	1.61	2.89	2.43	2.74	3.19	3.31	3.05
Total [1] [2] *($/BOE)*									
Price	33.91	40.50	27.73	58.29	46.14	61.85	62.76	65.71	59.68
Royalties	1.51	2.13	0.93	4.53	3.80	4.79	4.78	5.36	4.19
Transportation and Blending	4.03	3.95	4.11	2.32	2.40	2.39	2.24	2.45	2.03
Operating	11.20	10.94	11.44	13.22	11.57	12.53	14.44	13.95	14.94
Production and Mineral Taxes	0.22	0.27	0.17	0.44	0.36	0.48	0.47	0.65	0.28
Netback	16.95	23.21	11.08	37.78	28.01	41.66	40.83	43.30	38.24
Impact of Long-Term Incentives Costs (Recovery) on Total Operating Costs *($/BOE)*	0.05	0.16	(0.05)	0.16	(0.09)	0.08	0.33	0.36	0.29
Impact of Realized Gain (Loss) on Risk Management									
Liquids *($/bbl)*	4.27	1.75	6.58	0.50	7.06	(0.45)	(2.48)	(2.94)	(2.00)
Natural Gas *($/Mcf)*	0.34	0.39	0.29	0.04	0.05	0.11	(0.01)	(0.02)	-
Total [2] *($/BOE)*	3.67	1.92	5.31	0.42	5.17	(0.13)	(1.76)	(2.09)	(1.42)

[1] The netbacks do not reflect non-cash write-downs of product inventory.

[2] Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). 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.

ADVISORY

FINANCIAL INFORMATION

Basis of Presentation Cenovus reports financial results in Canadian dollars and presents production volumes on a net to Cenovus before royalties basis, unless otherwise stated. Cenovus prepares its financial statements in accordance with International Financial Reporting Standards (IFRS).

Non-GAAP Measures This quarterly report contains references to non-GAAP measures as follows:

- Operating cash flow is defined as revenues, less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains, less realized losses on risk management activities and is used to provide a consistent measure of the cash generating performance of the company's assets for comparability of Cenovus's underlying financial performance between periods. Items within the Corporate and Eliminations segment are excluded from the calculation of operating cash flow.
- 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, both of which are defined on the Consolidated Statement of Cash Flows in Cenovus's interim and annual Consolidated Financial Statements. Cash flow is a 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.
- Free cash flow is defined as cash flow less capital investment.
- Operating earnings is used to provide a consistent measure of the comparability of the company's 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, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on operating earnings (loss) before tax, excluding the effect of changes in statutory income tax rates.
- Debt to capitalization, net debt to capitalization, debt to adjusted EBITDA and net debt to adjusted EBITDA are ratios that management uses to steward the company's overall debt position as measures of the company's overall financial strength. Debt is defined as short-term borrowings and long-term debt, including the current portion. Net debt is defined as debt net of cash and cash equivalents. Capitalization is defined as debt plus shareholders' equity. Net debt to capitalization is defined as net debt divided by net debt plus shareholders' equity. Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, goodwill and asset impairments, unrealized gain or loss on risk management, foreign exchange gains or losses, gains or losses on divestiture of assets and other income and loss, calculated on a trailing 12-month basis.

These measures do not have a standardized meaning as prescribed by International Financial Reporting Standards (IFRS) and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this quarterly report in order to provide shareholders and potential investors with additional information regarding Cenovus's liquidity and its ability to generate funds to finance its operations. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For further information, refer to Cenovus's second quarter 2015 Management's Discussion & Analysis (MD&A) available at cenovus.com.

OIL AND GAS INFORMATION

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 barrel (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. Given that the value ratio based on the current price of crude oil compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Netbacks reported in this quarterly report are calculated as set out in the Annual Information Form (AIF). Heavy oil prices and transportation and blending costs exclude the costs of purchased condensate, which is blended with heavy oil. For the second quarter of 2015, the cost of condensate on a per barrel of unblended crude oil basis was as follows: Christina Lake - $32.90 and Foster Creek - $29.82.

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about Cenovus's current expectations, estimates and projections, made in light of the company's 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", "projected", "future", "could", "should", "focus", "proposed", "schedule", "potential", "capacity", "may", "strategy", "priority", "outlook" or similar expressions and includes suggestions of future outcomes, including statements about: the strength of the company's position to support future investment and delivery of value under various potential conditions; adequacy of the company's liquidity to manage through the current low-price environment; growth strategy and related schedules, including priorities and focus; projections contained in the company's updated 2015 guidance; forecast operating and financial results; planned capital expenditures, capital investment priorities and expected conditions for future capital investments; project capacities; expected future production, including the timing, stability or growth thereof; improving cost structures, including relative to cost reduction targets, the expected timing, sustainability and potential impacts of anticipated cost savings and potential outcomes of the company's assessment of its workforce and G&A requirements; the expected timing and potential impacts of the transition to a new functional model; the long-term potential of the company's emerging projects; expected impacts of the disposition of Heritage Royalty Limited Partnership; expected impacts and timeline for closing of the crude-by-rail trans-loading facility acquisition; acquisition and disposition strategy; forecast natural gas use at operations; expected SOR; expected increase in production capacity through optimization activity; potential for optimization of engineering and execution strategy, including related impacts on capital efficiencies; operating cash flow relative to ongoing capital investment requirements for properties; expected future refining capacity; expected pipeline capacity; broadening market access; the company's work on a variety of oil blends, including potential related impact on transportation and refining options; dividend plans and dividend strategy, including with respect to the dividend reinvestment plan; anticipated timelines for future regulatory, partner or internal approvals; forecasted commodity prices; future use and development of technology; targeted future debt to capitalization ratio and debt to adjusted EBITDA; and projected shareholder value and total shareholder return. Readers are cautioned not to place undue reliance on forward-looking information, as the company's 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 Cenovus's current guidance, available at cenovus.com; the company's projected capital investment levels, the flexibility of the company's 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; the company's ability to obtain necessary regulatory and partner approvals and closing of the crude-by-rail trans-loading facility acquisition; the successful and timely implementation of capital projects or stages thereof; the company's ability to generate sufficient cash flow to meet its current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2015 guidance is based on an average diluted number of shares outstanding of approximately 819 million. It assumes: Brent of US$62.25/bbl, WTI of US$56.75/bbl; WCS of US$44.00/bbl; NYMEX of US$2.85/MMBtu; AECO of $2.65/GJ; Chicago 3-2-1 crack spread of US$18.50/bbl; and an exchange rate of $0.81 US$/C$.

The risk factors and uncertainties that could cause Cenovus's actual results to differ materially include: risks inherent to completion of the company's crude-by-rail trans-loading facility acquisition, including obtaining any necessary regulatory or other third-party approvals and satisfying other closing conditions in connection therewith; volatility of and assumptions regarding oil and natural gas prices; the effectiveness of the company's risk management program, including the impact of derivative financial instruments, the success of the company's hedging strategies and the sufficiency of its liquidity position; 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 Cenovus's marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA, net debt to adjusted EBITDA, debt to capitalization and net debt to capitalization; ability to access various sources of debt and equity capital, generally, and on terms acceptable to Cenovus; changes in credit ratings applicable to Cenovus or any of its securities; changes to Cenovus's dividend plans or strategy, including the dividend reinvestment plan; accuracy of Cenovus's reserves, resources and future production estimates; ability to replace and expand oil and gas reserves; ability to maintain the company's relationships with its partners and to successfully manage and operate its integrated heavy oil business; reliability of the company's assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to Cenovus's business; the timing and the costs of well and pipeline construction; the company's 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 Cenovus operates, 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 Cenovus's business, its financial results and its consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which Cenovus operates; 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 Cenovus.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of Cenovus's material risk factors, see "Risk Factors" in our AIF or Form 40-F for the year ended December 31, 2014 and "Risk Management" in our current and annual Management's Discussion and Analysis (MD&A), available on SEDAR at sedar.com, EDGAR at sec.gov and on the company's 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
BOE/d	barrel of oil equivalent per day
MBOE	thousand barrel of oil equivalent
TM	Trademark of Cenovus Energy Inc.

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