Cenovus finishes 2015 with strong balance sheet
Additional budget reductions planned to preserve financial resilience

Calgary, Alberta (February 11, 2016) – Cenovus Energy Inc. (TSX: CVE) (NYSE: CVE) achieved significant sustainable cost savings across its business in 2015 and further strengthened what is now one of the best balance sheets in the North American exploration and production sector. The company is planning additional measures in 2016 to help it remain financially resilient through another year of expected low crude oil and natural gas prices. These measures include reducing 2016 capital, operating and general and administrative (G&A) spending by another $400 million to $500 million.

Planned 2016 measures to maintain financial resilience

- Reduce planned capital spending by $200 million to $300 million to between $1.2 billion and $1.3 billion
- Decrease operating and G&A expenses, including workforce costs, by $200 million
- Reduce first quarter dividend by 69% to $0.05 per share

Key 2015 developments

- Exited 2015 with more than $8 billion in liquidity, including cash, cash equivalents and undrawn credit facilities, as well as a net debt to capitalization ratio of 16%
- Cut capital spending by 44% or $1.3 billion compared with 2014
- Achieved better than expected cost savings of approximately $540 million through capital, operating and G&A spending reductions
- Reduced oil sands non-fuel operating costs by 19% to $7.66/barrel (bbl) from 2014
- Reduced workforce by 24% compared with 2014 levels
- Increased 2015 proved reserves by 7% compared with 2014, while decreasing finding and development (F&D) costs by 60% to $5.31/bbl

2015 production & financial summary

(for the period ended December 31) Production (before royalties)	**2015 Q4**	2014 Q4	% change	**2015 Full Year**	2014 Full Year	% change
Oil sands (bbls/d)	**139,413**	142,213	-2	**140,320**	128,195	9
Conventional oil[1] (bbls/d)	**60,143**	73,964	-19	**66,627**	75,298	-12
Total oil (bbls/d)	**199,556**	216,177	-8	**206,947**	203,493	2
Natural gas (MMcf/d)	**424**	479	-11	**441**	488	-10
Financial ($ millions, except per share amounts)						
Cash flow[2]	**275**	401	-31	**1,691**	3,479	-51
Per share diluted	**0.33**	0.53		**2.07**	4.59	
Operating earnings[2]	**-438**	-590		**-403**	633	-164
Per share diluted	**-0.53**	-0.78		**-0.49**	0.84	
Net earnings	**-641**	-472		**618**	744	-17
Per share diluted	**-0.77**	-0.62		**0.75**	0.98	
Capital investment	**428**	786	-46	**1,714**	3,051	-44

[1] Includes natural gas liquids (NGLs).
[2] Cash flow and operating earnings are non-GAAP measures as defined in the Advisory.

In 2015, Cenovus took a number of decisive steps to improve its financial resilience and further reinforce its balance sheet. These measures have left the company in a strong position to face what it believes will be another challenging year for the energy sector with continued volatility and low commodity prices.

"By focusing on the aspects of our business that are within our control, we ended 2015 in an even stronger competitive position than we started it," said Brian Ferguson, Cenovus President & Chief Executive Officer. "We must remain focused on maintaining our financial resilience through 2016 and beyond, ensuring that we don't compromise the balance sheet strength we've worked so hard to achieve, so that we are well placed to maximize shareholder value when commodity prices improve."

Maintaining financial resilience

To help maintain its financial position for the year ahead, Cenovus is taking a number of additional steps. These include reducing planned capital spending by $200 million to $300 million compared with the company's original 2016 budget released in December. Cenovus now plans to spend between $1.2 billion and $1.3 billion, 27% less than in 2015 and 59% below 2014 levels. The company is also targeting additional operating and G&A cost savings of $200 million in 2016 to match expected activity levels.

Planned capital budget reductions for 2016 include lower spending at Cenovus's Foster Creek and Christina Lake oil sands operations, its emerging oil sands assets and the company's conventional oil business. The planned capital spending reductions are expected to have minimal impact on the company's oil sands production for 2016, which is forecast to remain within guidance, at between 144,000 barrels per day (bbls/d) net and 157,000 bbls/d net. Cenovus plans to continue focused investment in technology development to help drive potential cost efficiencies and improvements in environmental performance.

Cenovus has identified further opportunities to reduce operating and G&A expenses by prioritizing repairs and maintenance and cancelling or deferring non-essential work, including the deferral of a scheduled turnaround at Foster Creek until 2017. The company plans to continue optimizing its processes to help realize greater efficiencies and is working with its suppliers and service providers to find additional opportunities to reduce costs and increase productivity.

In 2016, Cenovus also plans to further reduce its workforce and adjust its discretionary spending and compensation programs while continuing to focus on retaining the core capabilities and expertise needed to execute on its business plan. The company is undertaking a thorough evaluation of all its staffing costs to align total compensation with the current business environment. This includes reassessing benefits, allowances and contractor rates. Cash compensation for Cenovus's President & Chief Executive Officer as well as the company's four other highest paid executives was reduced in 2015 and will be reduced further in 2016. These workforce measures are expected to account for approximately 40% of the planned $200 million in 2016 operating and G&A cost savings.

Dividend update

To help preserve Cenovus's financial resilience during this prolonged period of low oil prices, the company is reducing its dividend by 69% from the fourth quarter of 2015. For the first quarter of 2016, the Board of Directors has declared a dividend of $0.05 per share, payable on March 31, 2016 to common shareholders of record as of March 15, 2016. Based on the February 10, 2016 closing share price on the Toronto Stock Exchange of $13.52, this represents an annualized yield of about 1.5%. Declaration of dividends is at the sole discretion of the Board and will continue to be evaluated on a quarterly basis.

“Capital discipline and balance sheet strength will remain our top priorities in this extremely challenging oil price environment,” said Ferguson. “We now have some of the fiscal and regulatory clarity at the provincial level necessary to make decisions about future growth. However, we still require additional certainty around federal fiscal and regulatory regimes and sustained cost reductions at our operations before committing to restart deferred projects.”

Guidance update
As a result of its planned capital, operating and G&A cost reductions for 2016, Cenovus has updated its guidance for the year. The revised guidance is available at cenovus.com under “Investors.”

2015 overview

Cenovus had a strong operational year in 2015, increasing its oil sands production by 9% and growing its proved reserves by 7% compared with 2014. At the same time, the company achieved its best-ever safety performance with a total recordable injury frequency (TRIF) of 0.39, a 40% improvement from the previous year.

Balance sheet strength
With the proceeds from the sale of its royalty and fee land business in July and a bought-deal common share issuance in March, the company finished 2015 with cash and cash equivalents on its balance sheet of $4.1 billion. Including the cash on hand and $4 billion in undrawn capacity under its committed credit facility, Cenovus has approximately $8 billion in liquidity available today, with no debt maturing until the fourth quarter of 2019. At the end of 2015, the company’s net debt to capitalization ratio was 16% and its net debt to adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) was 1.2 times.

In 2015, Cenovus realized substantial reductions of approximately $540 million in capital, operating and G&A costs. These cost savings were more than twice the $200 million in annual savings the company had originally targeted at the beginning of 2015. Of Cenovus’s 2015 savings, approximately 60% came from operating and G&A cost improvements, while the remaining 40% came from capital cost reductions, primarily due to greater capital efficiency.

Cenovus anticipates approximately 60% of its 2015 cost savings will be sustainable over the long term. The cost reductions included savings related to improved drilling efficiency, optimized scheduling and prioritization of repair and maintenance activities as well as reduced chemical costs and better oil sands waste disposal and handling processes. About one-quarter of Cenovus’s 2015 cost savings were the result of work that has been deferred.

Oil sands growth

Cenovus increased production from its Foster Creek and Christina Lake oil sands projects by 9% in 2015 while significantly reducing per-unit operating costs compared with the previous year. Lower operating costs were the result of decreased natural gas prices, an increase in production volumes and a decrease in facility and well maintenance expenses. Oil sands operating costs declined $3.37/bbl or 25% to $10.13/bbl in 2015. This included a 19% decrease in non-fuel operating costs to $7.66/bbl.

The year-over-year production increase was largely due to the ramp-up of new wells associated with phase F at Foster Creek as well as improved facility performance and the ramp-up of additional sustaining wells at Christina Lake.

With the new production capacity that's recently come on stream and more nearing completion, Cenovus believes it is well positioned for when commodity prices recover. The recently completed Christina Lake optimization project is expected to ramp up through 2016. Cenovus is now concentrating on delivering its two oil sands expansion projects that are almost complete. The Foster Creek phase G and Christina Lake phase F expansions are on track with first oil from both projects anticipated in the third quarter of 2016. Together, these two expansion projects, plus the Christina Lake optimization, are expected to add approximately 100,000 bbls/d of incremental gross production capacity (50,000 bbls/d net), an increase of about 35% to Cenovus's current oil sands production capacity.

Financial results

In 2015, the significant decrease in average benchmark commodity prices compared with 2014 resulted in a 50% decrease in Cenovus's average crude oil sales price and a 33% decline in its average natural gas sales price. This contributed to a more than 40% decrease in the company's 2015 operating cash flow to $2.4 billion. Upstream operating cash flow was down by nearly 50% to $2.1 billion.

Operating cash flow from refining and marketing grew by almost 80% to $385 million in 2015, 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. This was partially offset by higher heavy crude oil feedstock costs relative to the West Texas Intermediate (WTI) benchmark price and higher reported operating costs as a result of exchange rate fluctuation.

Leadership appointments

Cenovus is pleased to announce the hiring of Kieron McFadyen, who will be joining the company as Executive Vice-President & President, Upstream Oil & Gas on April 6. He will be responsible for all of Cenovus's oil sands and conventional operations. McFadyen most recently held a senior position with a major international integrated oil and gas company. A mechanical engineer by training, he has acquired an impressive breadth of experience in a number of countries and in a variety of roles over his 30-year career.

"We are delighted that Kieron will be joining us," said Ferguson. "He has a strong technical and operational background, a noteworthy track record of value creation, change leadership and stakeholder management, and will be an excellent addition to the Cenovus Leadership Team."

2015 and fourth quarter details

Oil sands

Christina Lake

- Production averaged 74,975 bbls/d net in 2015, 9% more than in 2014, due to incremental volumes from additional wells and improved performance of facilities.
- In the fourth quarter, production averaged 75,733 bbls/d net, a 3% increase from the same period in 2014.
- Operating costs were $8.01/bbl in 2015, a decline of 28% from 2014. Non-fuel operating costs were $5.81/bbl, 22% lower than in 2014.
- The steam to oil ratio (SOR), the amount of steam needed to produce a barrel of oil, was 1.7 in 2015, a slight improvement from 1.8 in 2014.
- Netbacks were $15.05/bbl in 2015, down 65% from 2014.
- In December 2015, Cenovus received regulatory approval from the Alberta Energy Regulator for phase H, a potential future expansion that would add 50,000 bbls/d of incremental gross production capacity.

Foster Creek

- Production averaged 65,345 bbls/d net in 2015, 10% higher than in 2014, due to the ramp-up of volumes from phase F and production from new wells. The gain was partially offset by the impact of a forest fire in the second quarter, which decreased production by approximately 2,600 bbls/d net on an annualized basis.
- Operating costs at Foster Creek decreased 23% to $12.60/bbl in 2015. Non-fuel operating costs were $9.80/bbl, an 18% decline from a year earlier.
- The SOR was 2.5 in 2015, an improvement from 2.6 in 2014.
- Netbacks were $11.74/bbl in 2015, a 74% decline from the previous year.
- New reservoir management techniques Cenovus has been working on over the past couple of years to improve wellbore conformance and well productivity at Foster Creek have yielded excellent results. These enhancements, which include downhole instrumentation and optimization work, as well as steam circulation start-up on new pads, have increased wellbore conformance at Foster Creek from between 70% to 75% previously to approximately 90%, similar to Christina Lake. The improved wellbore conformance has accelerated production from more mature wells, which has led to faster declines at those wells, as expected.
- Unrelated to the improved wellbore conformance, Foster Creek had a higher than average percentage of wells down for servicing at the end of 2015. Cenovus usually expects 3% to 4% of its wells to be down at any given time in a field the size of Foster Creek. Approximately 7% of producing well pairs were offline at the end of the year for a variety of reasons, including pump changes, instrumentation, testing of different completions, regular maintenance and some mechanical issues.
- In accordance with the company's strategy to focus on value-driven production, Cenovus decided in 2015 not to address well outages as quickly as it would have in a higher price environment. To preserve capital, the company also chose in 2015 to defer some planned new well pads. These decisions, combined with the faster declines due to improved wellbore conformance and well productivity, contributed to lower fourth quarter volumes of 63,680 bbls/d net, a 7% decrease from the same period in 2014.

- Cenovus expects to increase its maintenance program to return well outages to normal levels. The company plans to bring on up to seven new well pads in 2016, which is expected to increase volumes through the year. Cenovus anticipates production at Foster Creek to average between 60,000 bbls/d and 65,000 bbls/d net in the first half of 2016 and between 65,000 bbls/d and 70,000 bbls/d net in the second half of the year, exiting 2016 above 70,000 bbls/d net.
- Cenovus is focused on driving its sustaining capital and F&D costs lower. The company believes that better wellbore conformance and well productivity at both Foster Creek and Christina Lake will help reduce these costs by providing Cenovus with the potential to enhance its development strategy through the use of longer horizontal wells and wider spacing. In addition, the company expects that Wedge Well™ technology may not be required between all of its well pairs and going forward would be considered on a case-by-case basis.

Conventional oil

- Total conventional oil production decreased 12% to 66,627 bbls/d in 2015 compared with the previous year, primarily due to a deferral of capital spending, expected natural declines, the sale of non-core assets in 2014 and the divestiture of Cenovus's royalty and fee land business in 2015. The decline was partially offset by successful horizontal well performance in southern Alberta.
- In the fourth quarter, production decreased 19% to 60,143 bbls/d compared with the same period in 2014.
- Operating costs were $15.78/bbl in 2015, 15% lower than in 2014.

Natural gas

- Natural gas production averaged 441 million cubic feet per day (MMcf/d) in 2015, down 10% from 2014, primarily due to expected natural declines and the company's 2015 sale of its royalty and fee land business.
- In the fourth quarter, natural gas production declined 11% to 424 MMcf/d, compared with the final quarter of 2014.
- Operating costs fell 2% to $1.20 per thousand cubic feet (Mcf) in 2015 compared with 2014.

Downstream

- Cenovus's Wood River Refinery in Illinois and Borger Refinery in Texas, which are jointly owned with the operator, Phillips 66, had continued strong performance in 2015. This included:
  - processing a combined average of 419,000 bbls/d gross of crude oil (91% utilization), compared with 423,000 bbls/d gross in 2014
  - processing an average of 200,000 bbls/d gross of heavy oil compared with 199,000 bbls/d gross in 2014
  - producing an average of 444,000 bbls/d gross of refined products, little changed from 445,000 bbls/d gross a year earlier.
- Refinery operating results from the fourth quarter of 2015 included:
  - processing a combined average of 405,000 bbls/d gross of crude oil (88% utilization), compared with 420,000 bbls/d gross in the same period in 2014
  - processing an average of 196,000 bbls/d gross of heavy oil compared with 179,000 bbls/d gross in the year-earlier period

- producing an average of 430,000 bbls/d gross of refined products, compared with 442,000 bbls/d gross a year earlier.

- Operating cash flow from refining and marketing was $385 million in 2015, up from $215 million the previous year. This includes a $15 million inventory write-down, compared with a write-down of $113 million in 2014. 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 $52 million higher in 2015, compared with $101 million higher in 2014.

Financial

Corporate and financial information

- Total cash flow decreased by 51% to nearly $1.7 billion, primarily due to lower crude oil and natural gas sales prices.
- Operating cash flow was $2.4 billion in 2015, down 42% from 2014, largely due to lower crude oil and natural gas sales prices and a decline in natural gas sales volumes. The decrease was partially offset by realized risk management gains of $613 million, excluding refining and marketing, as well as lower royalties and reduced operating expenses.
- In 2015, Cenovus had capital spending of approximately $1.7 billion, nearly 70% of which was directed towards its oil sands assets. Total capital spending for the year was down 44%, or $1.3 billion, from 2014 and was approximately $150 million below the company's guidance for 2015.
- In 2015, Cenovus invested nearly $1.2 billion in its oil sands assets, 40% lower than in 2014. Investment in conventional oil and natural gas was $245 million, 71% lower than the previous year, while refining and marketing investment was $248 million, a 52% increase. The company also invested $37 million in corporate assets, a 40% decline from 2014.
- For the year, operating cash flow in excess of capital invested was $452 million from the company's conventional oil business, $293 million from natural gas and $137 million from refining and marketing. Capital investment in Cenovus's oil sands business exceeded operating cash flow by $138 million.
- In 2015 Cenovus recorded inventory write-downs and asset impairments of $404 million, compared with $779 million in 2014. The 2015 impairments included a $184 million property, plant and equipment impairment charge related to the company's conventional assets in northern Alberta. The company also recorded exploration expense of approximately $138 million for oil sands and conventional properties deemed not to be commercially viable or technically feasible as well as $66 million in inventory write-downs due to the decline in forward commodity prices.
- After investing approximately $1.7 billion in 2015, Cenovus had a free cash flow shortfall of $23 million compared with free cash flow of $428 million in 2014.
- Net income fell 17% to $618 million in 2015. The decrease was primarily due to a decline in operating earnings, unrealized foreign exchange losses on the company's U.S.-dollar denominated debt of $1.1 billion and unrealized risk management losses of $195 million compared with gains in 2014. The decrease was offset by an after-tax gain of approximately $1.9 billion from the divestiture of its royalty and fee land business and a deferred tax recovery compared with an expense in 2014.

- G&A expenses were $335 million in 2015, 12% lower than in 2014. The decrease was primarily due to workforce reductions and lower employee long-term incentive costs driven by the decline in the company's share price. Lower discretionary spending also contributed to the decrease, partially offset by severance costs of $43 million.
- At December 31, 2015, the company's net debt to capitalization ratio was 16% and net debt to adjusted EBITDA was 1.2 times. The debt to capitalization ratio was 34% and debt to adjusted EBITDA was 3.1 times. 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. The company expects these ratios may be outside of the target ranges at different points in the economic cycle.

Commodity price hedging

- Cenovus had realized after-tax hedging gains of $481 million in 2015, as the company's contract prices exceeded average benchmark prices. The company had unrealized after-tax hedging losses of $141 million in 2015.
- From mid-December 2015 through January 2016, Cenovus added 29,000 bbls/d of Brent fixed-price contracts for the first half of 2016 at an average price of US$39.48/bbl and 10,000 bbls/d of WTI fixed-price contracts for the second half of the year at an average price of US$39.02/bbl. As of January 31, 2016, the company had approximately 24% of its oil production hedged for the remainder of the year at a volume-weighted average floor price of about C$72.31/bbl.
- Including hedging, market access commitments and downstream integration largely provided by the company's two U.S. refineries, Cenovus has positioned itself to mitigate the impact of swings in the Canadian light-heavy oil price differential for more than 85% of its anticipated 2016 heavy oil production. Together, these mechanisms help to support Cenovus's financial resilience during this challenging period for the industry.

Reserves and resources

All of Cenovus's reserves and resources are evaluated each year by independent qualified reserves evaluators (IQREs).

- At year-end 2015, Cenovus had total proved reserves of approximately 2.5 billion BOE, an increase of 7%, or 167 million BOE, compared with 2014.
- Proved bitumen reserves for 2015 rose 11% compared with 2014 to approximately 2.2 billion barrels, while proved plus probable bitumen reserves remained unchanged at approximately 3.3 billion barrels. The increase in proved bitumen reserves was primarily due to Christina Lake proved reserves additions of 234 million barrels from improved reservoir performance and the regulatory approval of the Kirby East area expansion, which converted probable reserves to proved reserves.
- Bitumen best estimate economic contingent resources remained unchanged at 9.3 billion barrels compared with 2014.
- Cenovus's 2015 proved reserves F&D costs, excluding changes in future development costs, were $5.31/BOE, down 60% from $13.39/BOE in 2014, due to reduced capital spending and higher proved reserves additions in 2015. Three-year average F&D costs were $10.56/BOE, excluding changes in future development costs. The 2015 recycle ratio was 2.7 times.

- More details about Cenovus's reserves and contingent resources are available under Oil and Gas Information in the Advisory. Further information about the company's reserves is also available in Cenovus's Annual Information Form (AIF), while additional details about its resources can be found in the supplemental Statement of Contingent and Prospective Resources. These documents are available on SEDAR at sedar.com, EDGAR at sec.gov and on Cenovus's website at cenovus.com.

Recognitions

- In 2015, Cenovus was again recognized as a global leader in sustainable development through its inclusion in the Dow Jones Sustainability North America Index for the sixth consecutive year and the Dow Jones Sustainability World Index for the fourth consecutive year. The company was also listed on the CDP Canada 200 Climate Disclosure Leadership Index for the sixth consecutive year.
- Cenovus was also recently included, for the third year in a row, in the RobecoSAM Sustainability Yearbook. The publication lists the world's most sustainable companies in each industry as determined by their score in the RobecoSAM annual Corporate Sustainability Assessment, the same assessment used to create the Dow Jones Sustainability Index Series.

Conference Call Today

9 a.m. Mountain Time (11 a.m. Eastern Time)

Cenovus will host a conference call today, February 11, 2016, starting at 9 a.m. MT (11 a.m. ET). To participate, please dial 888-231-8191 (toll-free in North America) or 647-427-7450 approximately 10 minutes prior to the conference call. A live audio webcast of the conference call will also be available via cenovus.com. The webcast will be archived for approximately 90 days.

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).

Reclassification of Employee Stock-Based Compensation Costs

Employee stock-based compensation costs previously included in operating expense have been reclassified to G&A expense to conform to the presentation adopted for the year ended December 31, 2015. As a result, for the years ended December 31, 2014 and 2013, expenses of $21 million and $16 million, respectively, were reclassified. For further information, refer to Cenovus's 2015 annual Consolidated Financial Statements and Management's Discussion and Analysis (MD&A).

Non-GAAP Measures

This news release 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 and the recognition of an increase in U.S. tax basis.
- 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 gains or losses 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 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 news release 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 most recent Management's Discussion and Analysis (MD&A) available at cenovus.com.

OIL AND GAS INFORMATION

The estimates of reserves and resources data and related information were prepared effective December 31, 2015 by independent qualified reserves evaluators ("IQREs"), based on the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. ("McDaniel") January 1, 2016 price forecast.

Resources Information

Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% probability that the actual quantities recovered will equal or exceed the estimate. Contingent resources are those quantities of bitumen estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. The McDaniel estimates of contingent resources have not been adjusted for risk based on the chance of development. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. Economic contingent resources are estimated using volumetric calculations of the in-place quantities, combined with performance from analog reservoirs. Existing SAGD projects that are producing from the McMurray-Wabiskaw formations are used as performance analogs at Foster Creek and Christina Lake. Other regional analogs are used for contingent resources estimation in the Cretaceous Grand Rapids formation at the Grand Rapids property in the Greater Pelican region, in the McMurray formation at the Telephone Lake property in the Borealis region and in the Clearwater formation in the Foster Creek region.

Contingencies which must be overcome to enable the reclassification of contingent resources as reserves can be categorized as economic, non-technical and technical. The COGE Handbook identifies non-technical contingencies as legal, environmental, political and regulatory matters or a lack of markets. Technical contingencies include available infrastructure and project justification. The outstanding contingencies applicable to our disclosed economic contingent resources do not include economic contingencies.

Our bitumen contingent resources are located in four general regions: Foster Creek, Christina Lake, Borealis and Greater Pelican. Further information with respect to contingent resources including project descriptions, significant factors relevant to the resource estimates, and contingencies which prevent the classification of contingent resources as reserves is contained in our supplemental Statement of Contingent and Prospective Resources for the year ended December 31, 2015, which is available on SEDAR at sedar.com and the company's website at cenovus.com.

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

Netbacks reported in this news release are calculated as set out in the AIF. Heavy oil prices and transportation and blending costs exclude the costs of purchased condensate, which is blended with heavy oil. For 2015, the cost of condensate on a per barrel of unblended crude oil basis was as follows: Christina Lake - $27.39 and Foster Creek - $25.96.

Finding and Development Costs
Finding and development costs were calculated by dividing the sum of exploration costs and development costs in the particular period by the reserves additions (the sum of extensions and improved recovery, discoveries, technical revisions and economic factors) in that period. The aggregate of the exploration and development costs incurred in a particular period generally will not reflect total finding and development costs related to reserves additions for that period.

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”, “estimate”, “plan”, “forecast” or “F”, “future”, “target”, "guidance", "budget", “position”, "priority", “project”, “capacity”, “could”, “focus”, “potential”, “may”, “strategy”, “forward”, “opportunity”, “on track” or similar expressions and includes suggestions of future outcomes, including statements about: measures planned to help the company remain financially resilient through another year of expected low crude oil and natural gas prices; projections contained in the company's 2016 guidance; forecast operating and financial results; dividend plans and strategy; expected reserves and resources; forecast commodity prices; the strength of the company's position to face another challenging year for the energy sector with continued volatility and low commodity prices and when commodity prices recover; planned capital expenditures and reductions, and the expected impact on the company's upstream production for 2016; expectations regarding improving cost structures, forecast cost savings and the sustainability of cost savings; expected future production, including the timing, stability or growth thereof; future use and development of technology, including expected effects on environmental impact; the company's plans to continue optimizing its processes and potential to realize greater efficiencies; opportunities to further reduce costs and increase productivity, including the company's plans for further workforce reductions and adjustments to discretionary spending and compensation programs; Cenovus's priorities in the challenging commodity price environment; development strategy and related schedules; project capacities; expected future maintenance program and impacts on well outage levels; expected impacts of better wellbore conformance and well productivity, including with respect to future capital and cost structures; expectations regarding future requirements with respect to Wedge Well™ technology and potential impacts to future capital and cost structures; the company's

position to mitigate the impact of swings in the Canadian light-heavy oil price differential; and the company's financial resilience generally. 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 inherent in Cenovus's current guidance, available at cenovus.com; projected capital investment levels, the flexibility of 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; 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 Cenovus makes with securities regulatory authorities.

2016 guidance (as updated on February 11, 2016), available at cenovus.com, assumes: Brent of US$52.75/bbl, WTI of US$49.00/bbl; WCS of US$34.50/bbl; NYMEX of US$2.50/MMBtu; AECO of $2.50/GJ; Chicago 3-2-1 crack spread of US$12.00/bbl; and an exchange rate of $0.75 US$/C$.

The risk factors and uncertainties that could cause Cenovus's actual results to differ materially, include: 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; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in the company's marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of Cenovus's crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and net debt to capitalization; Cenovus's ability to access various sources of debt and equity capital, generally, and on terms acceptable to Cenovus; ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to Cenovus or any of its securities; changes to dividend plans or strategy, including the dividend reinvestment plan; accuracy of reserves, resources and future production estimates; ability to replace and expand oil and gas reserves; the company's ability to maintain relationships with partners and to successfully manage and operate the company's integrated business; reliability of assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of 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 costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and Cenovus's ability to attract and retain, critical talent; 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 the company.

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 the company's AIF or Form 40-F for the period ended December 31, 2015, available on SEDAR at sedar.com, EDGAR at sec.gov and on Cenovus's website at cenovus.com.

TM denotes a trademark of Cenovus Energy Inc.

Cenovus Energy Inc.

Cenovus Energy Inc. is a Canadian integrated oil company. It is committed to applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs. Operations include oil sands projects in northern Alberta, which use specialized methods to drill and pump the oil to the surface, and established natural gas and oil production in Alberta and Saskatchewan. The company also has 50% ownership in two U.S. refineries. Cenovus shares trade under the symbol CVE, and are listed on the Toronto and New York stock exchanges. Its enterprise value is approximately $14 billion. For more information, visit cenovus.com.

Find Cenovus on Facebook, Twitter, LinkedIn, YouTube and Instagram.

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CONSOLIDATED STATEMENTS OF EARNINGS (unaudited)

For the periods ended December 31,
($ millions, except per share amounts)

	Notes	Three Months Ended 2015	2014	Twelve Months Ended 2015	2014
Revenues	1				
Gross Sales		**2,955**	4,338	**13,207**	20,107
Less: Royalties		**31**	100	**143**	465
		2,924	4,238	**13,064**	19,642
Expenses	1				
Purchased Product		**1,808**	2,775	**7,374**	10,955
Transportation and Blending		**534**	577	**2,043**	2,477
Operating		**460**	488	**1,839**	2,045
Production and Mineral Taxes		**2**	10	**18**	46
(Gain) Loss on Risk Management	22	**(213)**	(567)	**(461)**	(662)
Depreciation, Depletion and Amortization	7,12	**659**	531	**2,114**	1,946
Goodwill Impairment	7	**-**	497	**-**	497
Exploration Expense	7,11	**117**	85	**138**	86
General and Administrative		**109**	65	**335**	379
Finance Costs	4	**123**	108	**482**	445
Interest Income		**(8)**	(2)	**(28)**	(33)
Foreign Exchange (Gain) Loss, Net	5	**204**	188	**1,036**	411
Research Costs		**7**	6	**27**	15
(Gain) Loss on Divestiture of Assets	6	**3**	1	**(2,392)**	(156)
Other (Income) Loss, Net		**1**	(4)	**2**	(4)
Earnings (Loss) Before Income Tax		**(882)**	(520)	**537**	1,195
Income Tax Expense (Recovery)	8	**(241)**	(48)	**(81)**	451
Net Earnings (Loss)		**(641)**	(472)	**618**	744
Net Earnings (Loss) Per Share	9				
Basic		**$(0.77)**	$(0.62)	**$0.75**	$0.98
Diluted		**$(0.77)**	$(0.62)	**$0.75**	$0.98

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (unaudited)

For the periods ended December 31,
($ millions)

	Notes	Three Months Ended 2015	2014	Twelve Months Ended 2015	2014
Net Earnings (Loss)		**(641)**	(472)	**618**	744
Other Comprehensive Income (Loss), Net of Tax	18				
Items That Will Not be Reclassified to Profit or Loss:					
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**15**	(7)	**20**	(18)
Items That May be Reclassified to Profit or Loss:					
Change in Value of Available for Sale Financial Assets		**6**	-	**6**	-
Foreign Currency Translation Adjustment		**124**	107	**587**	215
Total Other Comprehensive Income, Net of Tax		**145**	100	**613**	197
Comprehensive Income (Loss)		**(496)**	(372)	**1,231**	941

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)
As at
($ millions)

	Notes	December 31, 2015	December 31, 2014
Assets			
Current Assets			
Cash and Cash Equivalents		**4,105**	883
Accounts Receivable and Accrued Revenues		**1,251**	1,582
Income Tax Receivable		**6**	28
Inventories	10	**810**	1,224
Risk Management	22,23	**301**	478
Current Assets		**6,473**	4,195
Exploration and Evaluation Assets	1,11	**1,575**	1,625
Property, Plant and Equipment, Net	1,12	**17,335**	18,563
Income Tax Receivable		**90**	-
Other Assets		**76**	70
Goodwill	1,14	**242**	242
Total Assets		**25,791**	24,695
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities		**1,702**	2,588
Income Tax Payable		**133**	357
Risk Management	22,23	**23**	12
Current Liabilities		**1,858**	2,957
Long-Term Debt	15	**6,525**	5,458
Risk Management	22,23	**7**	4
Decommissioning Liabilities	16	**2,052**	2,616
Other Liabilities		**142**	172
Deferred Income Taxes		**2,816**	3,302
Total Liabilities		**13,400**	14,509
Shareholders' Equity		**12,391**	10,186
Total Liabilities and Shareholders' Equity		**25,791**	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 17)			(Note 18)	
Balance as at December 31, 2013	3,857	4,219	1,660	210	9,946
Net Earnings	-	-	744	-	744
Other Comprehensive Income (Loss)	-	-	-	197	197
Total Comprehensive Income (Loss)	-	-	744	197	941
Common Shares Issued Under Stock Option Plans	32	-	-	-	32
Stock-Based Compensation Expense	-	72	-	-	72
Dividends on Common Shares	-	-	(805)	-	(805)
Balance as at December 31, 2014	3,889	4,291	1,599	407	10,186
Net Earnings	-	-	618	-	618
Other Comprehensive Income (Loss)	-	-	-	613	613
Total Comprehensive Income (Loss)	-	-	618	613	1,231
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	-	39	-	-	39
Dividends on Common Shares	-	-	(710)	-	(710)
Balance as at December 31, 2015	**5,534**	**4,330**	**1,507**	**1,020**	**12,391**

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the periods ended December 31,
($ millions)

	Notes	Three Months Ended 2015	Three Months Ended 2014	Twelve Months Ended 2015	Twelve Months Ended 2014
Operating Activities					
Net Earnings (Loss)		**(641)**	(472)	**618**	744
Depreciation, Depletion and Amortization	7,12	**659**	531	**2,114**	1,946
Goodwill Impairment	7	**-**	497	**-**	497
Exploration Expense	7,11	**117**	85	**138**	86
Deferred Income Taxes	8	**(139)**	(37)	**(655)**	359
Unrealized (Gain) Loss on Risk Management	22	**26**	(416)	**195**	(596)
Unrealized Foreign Exchange (Gain) Loss	5	**219**	190	**1,097**	411
(Gain) Loss on Divestiture of Assets	6	**3**	1	**(2,392)**	(156)
Current Tax on Divestiture of Assets	6	**-**	-	**391**	-
Unwinding of Discount on Decommissioning Liabilities	4,16	**32**	30	**126**	120
Other		**(1)**	(8)	**59**	68
Net Change in Other Assets and Liabilities		**(26)**	(38)	**(107)**	(135)
Net Change in Non-Cash Working Capital		**73**	505	**(110)**	182
Cash From Operating Activities		**322**	868	**1,474**	3,526
Investing Activities					
Capital Expenditures – Exploration and Evaluation Assets	11	**(21)**	(81)	**(138)**	(279)
Capital Expenditures – Property, Plant and Equipment	12	**(406)**	(706)	**(1,576)**	(2,779)
Acquisition	13	**(4)**	-	**(84)**	-
Proceeds From Divestiture of Assets	6	**(1)**	1	**3,344**	276
Current Tax on Divestiture of Assets	6	**-**	-	**(391)**	-
Net Change in Investments and Other		**3**	(2)	**3**	(1,583)
Net Change in Non-Cash Working Capital		**(40)**	(10)	**(270)**	15
Cash From (Used in) Investing Activities		**(469)**	(798)	**888**	(4,350)
Net Cash Provided (Used) Before Financing Activities		**(147)**	70	**2,362**	(824)
Financing Activities					
Net Issuance (Repayment) of Short-Term Borrowings		**(6)**	(139)	**(25)**	(18)
Common Shares Issued, Net of Issuance Costs	17	**-**	-	**1,449**	-
Common Shares Issued Under Stock Option Plans		**-**	-	**-**	28
Dividends Paid on Common Shares	9	**(132)**	(201)	**(528)**	(805)
Other		**-**	-	**(2)**	(2)
Cash From (Used in) Financing Activities		**(138)**	(340)	**894**	(797)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(11)**	(3)	**(34)**	52
Increase (Decrease) in Cash and Cash Equivalents		**(296)**	(273)	**3,222**	(1,569)
Cash and Cash Equivalents, Beginning of Period		**4,401**	1,156	**883**	2,452
Cash and Cash Equivalents, End of Period		**4,105**	883	**4,105**	883

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 developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and 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 bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, 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. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.
- **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 Corporate and Eliminations segment is attributed to Canada, with the exception of unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

Employee stock-based compensation costs previously included in operating expense have been reclassified to general and administrative expense to conform to the presentation adopted for the year ended December 31, 2015. As a result, for the three months and year ended December 31, 2014, a recovery of $2 million and an expense of $21 million, respectively, were reclassified.

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 December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**651**	1,064	**351**	657	**2,030**	2,773
Less: Royalties	**3**	55	**28**	45	**-**	-
	648	1,009	**323**	612	**2,030**	2,773
Expenses						
Purchased Product	**-**	-	**-**	-	**1,883**	2,931
Transportation and Blending	**478**	494	**58**	83	**-**	-
Operating	**129**	145	**130**	162	**203**	183
Production and Mineral Taxes	**-**	-	**2**	10	**-**	-
(Gain) Loss on Risk Management	**(152)**	(97)	**(71)**	(36)	**(16)**	(18)
Operating Cash Flow	**193**	467	**204**	393	**(40)**	(323)
Depreciation, Depletion and Amortization	**189**	166	**403**	303	**51**	40
Goodwill Impairment	**-**	-	**-**	497	**-**	-
Exploration Expense	**67**	3	**50**	82	**-**	-
Segment Income (Loss)	**(63)**	298	**(249)**	(489)	**(91)**	(363)

	Corporate and Eliminations		Consolidated	
For the three months ended December 31,	**2015**	2014	**2015**	2014
Revenues				
Gross Sales	**(77)**	(156)	**2,955**	4,338
Less: Royalties	**-**	-	**31**	100
	(77)	(156)	**2,924**	4,238
Expenses				
Purchased Product	**(75)**	(156)	**1,808**	2,775
Transportation and Blending	**(2)**	-	**534**	577
Operating	**(2)**	(2)	**460**	488
Production and Mineral Taxes	**-**	-	**2**	10
(Gain) Loss on Risk Management	**26**	(416)	**(213)**	(567)
Depreciation, Depletion and Amortization	**16**	22	**659**	531
Goodwill Impairment	**-**	-	**-**	497
Exploration Expense	**-**	-	**117**	85
Segment Income (Loss)	**(40)**	396	**(443)**	(158)
General and Administrative	**109**	65	**109**	65
Finance Costs	**123**	108	**123**	108
Interest Income	**(8)**	(2)	**(8)**	(2)
Foreign Exchange (Gain) Loss, Net	**204**	188	**204**	188
Research Costs	**7**	6	**7**	6
(Gain) Loss on Divestiture of Assets	**3**	1	**3**	1
Other (Income) Loss, Net	**1**	(4)	**1**	(4)
	439	362	**439**	362
Earnings (Loss) Before Income Tax			**(882)**	(520)
Income Tax Expense (Recovery)			**(241)**	(48)
Net Earnings (Loss)			**(641)**	(472)

B) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**644**	1,054	**239**	478	**883**	1,532
Less: Royalties	**3**	53	**25**	43	**28**	96
	641	1,001	**214**	435	**855**	1,436
Expenses						
Transportation and Blending	**478**	494	**53**	77	**531**	571
Operating	**124**	140	**84**	111	**208**	251
Production and Mineral Taxes	**-**	-	**2**	9	**2**	9
(Gain) Loss on Risk Management	**(151)**	(97)	**(57)**	(34)	**(208)**	(131)
Operating Cash Flow	**190**	464	**132**	272	**322**	736

(1) Includes NGLs.

	Natural Gas					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**5**	9	**104**	164	**109**	173
Less: Royalties	**-**	2	**3**	2	**3**	4
	5	7	**101**	162	**106**	169
Expenses						
Transportation and Blending	**-**	-	**5**	6	**5**	6
Operating	**3**	4	**44**	48	**47**	52
Production and Mineral Taxes	**-**	-	**-**	1	**-**	1
(Gain) Loss on Risk Management	**(1)**	-	**(14)**	(2)	**(15)**	(2)
Operating Cash Flow	**3**	3	**66**	109	**69**	112

	Other					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**2**	1	**8**	15	**10**	16
Less: Royalties	**-**	-	**-**	-	**-**	-
	2	1	**8**	15	**10**	16
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**2**	1	**2**	3	**4**	4
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**-**	-	**6**	12	**6**	12

	Total Upstream					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**651**	1,064	**351**	657	**1,002**	1,721
Less: Royalties	**3**	55	**28**	45	**31**	100
	648	1,009	**323**	612	**971**	1,621
Expenses						
Transportation and Blending	**478**	494	**58**	83	**536**	577
Operating	**129**	145	**130**	162	**259**	307
Production and Mineral Taxes	**-**	-	**2**	10	**2**	10
(Gain) Loss on Risk Management	**(152)**	(97)	**(71)**	(36)	**(223)**	(133)
Operating Cash Flow	**193**	467	**204**	393	**397**	860

C) Geographic Information

	Canada		United States		Consolidated	
For the three months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**1,398**	2,269	**1,557**	2,069	**2,955**	4,338
Less: Royalties	**31**	100	**-**	-	**31**	100
	1,367	2,169	**1,557**	2,069	**2,924**	4,238
Expenses						
Purchased Product	**380**	541	**1,428**	2,234	**1,808**	2,775
Transportation and Blending	**534**	577	**-**	-	**534**	577
Operating	**277**	313	**183**	175	**460**	488
Production and Mineral Taxes	**2**	10	**-**	-	**2**	10
(Gain) Loss on Risk Management	**(208)**	(543)	**(5)**	(24)	**(213)**	(567)
Depreciation, Depletion and Amortization	**609**	490	**50**	41	**659**	531
Goodwill Impairment	**-**	497	**-**	-	**-**	497
Exploration Expense	**117**	85	**-**	-	**117**	85
Segment Income (Loss)	**(344)**	199	**(99)**	(357)	**(443)**	(158)

D) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the twelve months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**3,030**	5,036	**1,709**	3,225	**8,805**	12,658
Less: Royalties	**29**	236	**114**	229	**-**	-
	3,001	4,800	**1,595**	2,996	**8,805**	12,658
Expenses						
Purchased Product	**-**	-	**-**	-	**7,709**	11,767
Transportation and Blending	**1,815**	2,131	**230**	346	**-**	-
Operating	**531**	639	**561**	709	**754**	703
Production and Mineral Taxes	**-**	-	**18**	46	**-**	-
(Gain) Loss on Risk Management	**(404)**	(38)	**(209)**	(1)	**(43)**	(27)
Operating Cash Flow	**1,059**	2,068	**995**	1,896	**385**	215
Depreciation, Depletion and Amortization	**697**	625	**1,148**	1,082	**191**	156
Goodwill Impairment	**-**	-	**-**	497	**-**	-
Exploration Expense	**67**	4	**71**	82	**-**	-
Segment Income (Loss)	**295**	1,439	**(224)**	235	**194**	59

	Corporate and Eliminations		Consolidated	
For the twelve months ended December 31,	**2015**	2014	**2015**	2014
Revenues				
Gross Sales	**(337)**	(812)	**13,207**	20,107
Less: Royalties	**-**	-	**143**	465
	(337)	(812)	**13,064**	19,642
Expenses				
Purchased Product	**(335)**	(812)	**7,374**	10,955
Transportation and Blending	**(2)**	-	**2,043**	2,477
Operating	**(7)**	(6)	**1,839**	2,045
Production and Mineral Taxes	**-**	-	**18**	46
(Gain) Loss on Risk Management	**195**	(596)	**(461)**	(662)
Depreciation, Depletion and Amortization	**78**	83	**2,114**	1,946
Goodwill Impairment	**-**	-	**-**	497
Exploration Expense	**-**	-	**138**	86
Segment Income (Loss)	**(266)**	519	**(1)**	2,252
General and Administrative	**335**	379	**335**	379
Finance Costs	**482**	445	**482**	445
Interest Income	**(28)**	(33)	**(28)**	(33)
Foreign Exchange (Gain) Loss, Net	**1,036**	411	**1,036**	411
Research Costs	**27**	15	**27**	15
(Gain) Loss on Divestiture of Assets	**(2,392)**	(156)	**(2,392)**	(156)
Other (Income) Loss, Net	**2**	(4)	**2**	(4)
	(538)	1,057	**(538)**	1,057
Earnings Before Income Tax			**537**	1,195
Income Tax Expense (Recovery)			**(81)**	451
Net Earnings			**618**	744

E) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**3,000**	4,963	**1,239**	2,456	**4,239**	7,419
Less: Royalties	**29**	233	**103**	217	**132**	450
	2,971	4,730	**1,136**	2,239	**4,107**	6,969
Expenses						
Transportation and Blending	**1,814**	2,130	**213**	326	**2,027**	2,456
Operating	**511**	615	**381**	505	**892**	1,120
Production and Mineral Taxes	**-**	-	**16**	37	**16**	37
(Gain) Loss on Risk Management	**(400)**	(38)	**(157)**	4	**(557)**	(34)
Operating Cash Flow	**1,046**	2,023	**683**	1,367	**1,729**	3,390

(1) Includes NGLs.

	Natural Gas					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**22**	67	**450**	744	**472**	811
Less: Royalties	**-**	3	**11**	12	**11**	15
	22	64	**439**	732	**461**	796
Expenses						
Transportation and Blending	**1**	1	**17**	20	**18**	21
Operating	**15**	17	**175**	198	**190**	215
Production and Mineral Taxes	**-**	-	**2**	9	**2**	9
(Gain) Loss on Risk Management	**(4)**	-	**(52)**	(5)	**(56)**	(5)
Operating Cash Flow	**10**	46	**297**	510	**307**	556

	Other					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**8**	6	**20**	25	**28**	31
Less: Royalties	**-**	-	**-**	-	**-**	-
	8	6	**20**	25	**28**	31
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**5**	7	**5**	6	**10**	13
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Cash Flow	**3**	(1)	**15**	19	**18**	18

	Total Upstream					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2015**	2014	**2015**	2014	**2015**	2014
Revenues						
Gross Sales	**3,030**	5,036	**1,709**	3,225	**4,739**	8,261
Less: Royalties	**29**	236	**114**	229	**143**	465
	3,001	4,800	**1,595**	2,996	**4,596**	7,796
Expenses						
Transportation and Blending	**1,815**	2,131	**230**	346	**2,045**	2,477
Operating	**531**	639	**561**	709	**1,092**	1,348
Production and Mineral Taxes	**-**	-	**18**	46	**18**	46
(Gain) Loss on Risk Management	**(404)**	(38)	**(209)**	(1)	**(613)**	(39)
Operating Cash Flow	**1,059**	2,068	**995**	1,896	**2,054**	3,964

F) Geographic Information

For the twelve months ended December 31,	Canada 2015	Canada 2014	United States 2015	United States 2014	Consolidated 2015	Consolidated 2014
Revenues						
Gross Sales	**6,407**	10,604	**6,800**	9,503	**13,207**	20,107
Less: Royalties	**143**	465	**-**	-	**143**	465
	6,264	10,139	**6,800**	9,503	**13,064**	19,642
Expenses						
Purchased Product	**1,607**	2,310	**5,767**	8,645	**7,374**	10,955
Transportation and Blending	**2,043**	2,477	**-**	-	**2,043**	2,477
Operating	**1,129**	1,367	**710**	678	**1,839**	2,045
Production and Mineral Taxes	**18**	46	**-**	-	**18**	46
(Gain) Loss on Risk Management	**(435)**	(625)	**(26)**	(37)	**(461)**	(662)
Depreciation, Depletion and Amortization	**1,925**	1,790	**189**	156	**2,114**	1,946
Goodwill Impairment	**-**	497	**-**	-	**-**	497
Exploration Expense	**138**	86	**-**	-	**138**	86
Segment Income (Loss)	**(161)**	2,191	**160**	61	**(1)**	2,252

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 December 31, 2015 was $37 million and $(44) million, respectively (three months ended December 31, 2014 – $382 million and $(321) million). Cenovus's share of operating cash flow from FCCL and WRB for the year ended December 31, 2015 was $656 million and $367 million, respectively (year ended December 31, 2014 – $1,939 million and $214 million).

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

By Segment

As at	E&E (1) December 31, 2015	E&E (1) December 31, 2014	PP&E (2) December 31, 2015	PP&E (2) December 31, 2014
Oil Sands	**1,560**	1,540	**8,907**	8,606
Conventional	**15**	85	**3,720**	6,038
Refining and Marketing	**-**	-	**4,398**	3,568
Corporate and Eliminations	**-**	-	**310**	351
Consolidated	**1,575**	1,625	**17,335**	18,563

As at	Goodwill December 31, 2015	Goodwill December 31, 2014	Total Assets December 31, 2015	Total Assets December 31, 2014
Oil Sands	**242**	242	**11,069**	11,024
Conventional	**-**	-	**3,830**	6,211
Refining and Marketing	**-**	-	**5,844**	5,520
Corporate and Eliminations	**-**	-	**5,048**	1,940
Consolidated	**242**	242	**25,791**	24,695

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

By Geographic Region

As at	E&E December 31, 2015	E&E December 31, 2014	PP&E December 31, 2015	PP&E December 31, 2014
Canada	**1,575**	1,625	**13,028**	14,999
United States	**-**	-	**4,307**	3,564
Consolidated	**1,575**	1,625	**17,335**	18,563

As at	Goodwill December 31, 2015	Goodwill December 31, 2014	Total Assets December 31, 2015	Total Assets December 31, 2014
Canada	**242**	242	**20,627**	20,231
United States	**-**	-	**5,164**	4,464
Consolidated	**242**	242	**25,791**	24,695

I) Capital Expenditures [(1)]

For the periods ended December 31,	Three Months Ended 2015	Three Months Ended 2014	Twelve Months Ended 2015	Twelve Months Ended 2014
Capital				
Oil Sands	**239**	494	**1,185**	1,986
Conventional	**87**	219	**244**	840
Refining and Marketing	**89**	52	**248**	163
Corporate	**13**	21	**37**	62
	428	786	**1,714**	3,051
Acquisition Capital				
Oil Sands	**3**	-	**3**	15
Conventional	**-**	1	**1**	3
Refining and Marketing	**-**	-	**83**	-
	431	787	**1,801**	3,069

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

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.

To conform to the presentation adopted during the fourth quarter of 2015, separate Consolidated Statements of Earnings and Comprehensive Income have been presented.

These interim Consolidated Financial Statements of Cenovus were approved by the Audit Committee effective February 10, 2016.

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 year ended December 31, 2015.

B) New Accounting Standards and Interpretations not yet Adopted

Leases

On January 13, 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded.

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 "*Revenue From Contracts With Customers*" has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The Company is currently evaluating the impact of adopting IFRS 16 on the Consolidated Financial Statements.

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.

IFRS 15 is effective for annual periods beginning on or after January 1, 2018. Early adoption is 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		Twelve Months Ended	
For the periods ended December 31,	**2015**	2014	**2015**	2014
Interest Expense – Short-Term Borrowings and Long-Term Debt	**85**	73	**328**	285
Unwinding of Discount on Decommissioning Liabilities (Note 16)	**32**	30	**126**	120
Other	**6**	5	**28**	18
Interest Expense – Partnership Contribution Payable [(1)]	**-**	-	**-**	22
	123	108	**482**	445

(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		Twelve Months Ended	
For the periods ended December 31,	**2015**	2014	**2015**	2014
Unrealized Foreign Exchange (Gain) Loss on Translation of:				
U.S. Dollar Debt Issued From Canada	**212**	186	**1,064**	458
Other	**7**	4	**33**	(47)
Unrealized Foreign Exchange (Gain) Loss	**219**	190	**1,097**	411
Realized Foreign Exchange (Gain) Loss	**(15)**	(2)	**(61)**	-
	204	188	**1,036**	411

6. DIVESTITURES

On July 29, 2015, the Company completed the sale of Heritage Royalty Limited Partnership ("HRP"), a wholly-owned subsidiary, to a third party for gross cash proceeds of $3.3 billion, resulting in a gain of $2.4 billion. HRP is a royalty business consisting of approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. Cenovus 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 production from Cenovus's Pelican Lake and Weyburn assets. These assets and results of operations were reported in the Conventional segment.

The divestiture gave rise to a taxable gain for which the Company has recognized current tax expense of $391 million. The majority of HRP's assets had been acquired at a nominal cost and, as such, had minimal benefit from tax depreciation in prior years. For this reason, the current tax expense associated with the divestiture is specifically identifiable; therefore, it has been classified as an investing activity in the Consolidated Statements of Cash Flows.

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

In the third quarter of 2014, the Company completed the sale of certain Wainwright properties to a third party for net proceeds of $234 million, resulting in a gain of $137 million. These assets and results of operations were reported in the Conventional segment.

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 and results of operations were reported in the Conventional segment.

7. IMPAIRMENTS

A) Cash-Generating Unit ("CGU") Impairments

As indicators of impairment were noted due to the significant decline in forward commodity prices, the Company has tested its upstream CGUs for impairment.

Key Assumptions

As at December 31, 2015, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal or an evaluation of comparable asset transactions. Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2015 by independent qualified reserves evaluators.

Crude Oil and Natural Gas Prices

The forward prices used to determine future cash flows from crude oil and natural gas reserves are:

	2016	2017	2018	2019	2020	Average Annual % Change to 2026
WTI (US$/barrel) [1]	45.00	53.60	62.40	69.00	73.10	3.8%
WCS (C$/barrel) [2]	46.40	54.40	59.70	66.30	68.20	3.9%
AECO (C$/Mcf) [3] [4]	2.70	3.20	3.55	3.85	3.95	4.0%

(1) West Texas Intermediate ("WTI") crude oil.
(2) Western Canadian Select ("WCS") crude oil blend.
(3) Alberta Energy Company ("AECO") natural gas.
(4) Assumes gas heating value of one million British Thermal Units per thousand cubic feet.

Discount and Inflation Rates

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent and inflation is estimated at two percent, which is common industry practice and used by Cenovus's independent qualified reserves evaluators in preparing their reserves reports. Based on the individual characteristics of the asset, other economic and operating factors are also considered, which may increase or decrease the implied discount rate.

2015 Impairments

As at December 31, 2015, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount, resulting in an impairment loss of $184 million. The impairment was recorded as additional DD&A in the Conventional segment. The Northern Alberta CGU includes the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage. Future cash flows for the CGU declined due to lower forward crude oil prices, a decline in reserves estimates and a slowing down of the development plan. This was partially offset by lower future development and operating costs.

The recoverable amount was determined using fair value less costs of disposal. The fair value for producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, consistent with Cenovus's independent qualified reserves evaluators (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. As at December 31, 2015, the recoverable amount of the Northern Alberta CGU was estimated to be approximately $1.5 billion.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no impairments of goodwill in the year ended December 31, 2015.

Sensitivities

Changes to the assumed discount rate or forward price estimates over the life of the reserves independently would have the following impact on the 2015 impairment of the Northern Alberta CGU:

	One Percent Increase in the Discount Rate	**Five Percent Decrease in the Forward Price Estimates**
Increase to Impairment of PP&E	**157**	**336**

2014 Impairments

As at December 31, 2014, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount and the full amount of the impairment was attributed to goodwill. An impairment loss of $497 million was recorded as goodwill impairment on the Consolidated Statements of Earnings. The operating results of the CGU are included in the Conventional segment. Future cash flows for the CGU declined due to lower crude oil prices and a slowing down of the Pelican Lake development plan.

The recoverable amount was determined using fair value less costs of disposal. The fair value for producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, consistent with Cenovus's independent qualified reserves evaluators (Level 3). The fair value of E&E assets was determined using market comparable transactions (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 11 percent. To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed. As at December 31, 2014, the recoverable amount of the Northern Alberta CGU was estimated to be $2.3 billion.

B) Asset Impairments

Exploration and Evaluation Assets

During the fourth quarter of 2015, $117 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense. This impairment loss included $67 million and $50 million within the Oil Sands and Conventional segments, respectively.

During the second quarter of 2015, $21 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense in the Conventional segment.

In 2014, $82 million of previously capitalized E&E costs 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.

Property, Plant and Equipment, Net

In addition to the impairments recorded at the CGU level, DD&A expense includes the following asset impairments:

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2015**	2014	**2015**	2014
Development and Production (Note 12)	**16**	52	**16**	65
	16	52	**16**	65

During the fourth quarter of 2015, the Company impaired a sulphur recovery facility for $16 million, which was recorded in the Oil Sands segment. The Company did not have future plans for the assets and did not believe it would recover the carrying amount through a sale.

In 2014, the Company impaired equipment for $52 million. The Company did not have future plans for the equipment and did not believe it would recover the carrying amount through a sale. The asset was written down to fair value less costs of disposal. Additionally, a minor natural gas property was shut-in and abandonment commenced, resulting in an impairment of $13 million. These impairments were recorded in the Conventional segment.

8. INCOME TAXES

The provision for income taxes is:

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2015**	2014	**2015**	2014
Current Tax				
Canada	**(100)**	12	**586**	94
United States	**(2)**	(23)	**(12)**	(2)
Total Current Tax Expense (Recovery)	**(102)**	(11)	**574**	92
Deferred Tax Expense (Recovery)	**(139)**	(37)	**(655)**	359
	(241)	(48)	**(81)**	451

In 2015, the Company recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of the Company's refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets.

The Alberta government enacted a two percent increase in the corporate income tax rate effective July 1, 2015, increasing the statutory tax rate for the year to 26.1 percent. As a result, the Company's deferred income tax liability increased by $161 million for the year ended December 31, 2015. The Canadian statutory tax rate as at December 31, 2015 was 27.0 percent. The U.S. statutory tax rate has decreased to 38.0 percent from 38.1 percent in 2014.

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

For the periods ended December 31,	Twelve Months Ended 2015	2014
Earnings Before Income Tax	**537**	1,195
Canadian Statutory Rate	**26.1%**	25.2%
Expected Income Tax	**140**	301
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(41)**	(43)
Non-Deductible Stock-Based Compensation	**7**	13
Non-Taxable Capital Losses	**137**	74
Unrecognized Capital Losses Arising From Unrealized Foreign Exchange	**135**	50
Adjustments Arising From Prior Year Tax Filings	**(55)**	(16)
Derecognition (Recognition) of Capital Losses	**(149)**	(9)
Recognition of U.S. Tax Basis	**(415)**	-
Change in Statutory Rate	**161**	-
Foreign Exchange Gains (Losses) not Included in Net Earnings	**-**	(13)
Goodwill Impairment	**-**	125
Other	**(1)**	(31)
Total Tax	**(81)**	451
Effective Tax Rate	**(15.1)%**	37.7%

9. PER SHARE AMOUNTS

A) Net Earnings Per Share

For the periods ended December 31,	Three Months Ended 2015	2014	Twelve Months Ended 2015	2014
Net Earnings (Loss) – Basic and Diluted ($ millions)	**(641)**	(472)	**618**	744
Basic – Weighted Average Number of Shares (millions)	**833.3**	757.1	**818.7**	756.9
Dilutive Effect of Cenovus TSARs (1)	**-**	-	**-**	0.7
Dilutive Effect of Cenovus NSRs (2)	**-**	-	**-**	-
Diluted – Weighted Average Number of Shares	**833.3**	757.1	**818.7**	757.6
Net Earnings (Loss) Per Share ($)				
Basic	**$(0.77)**	$(0.62)	**$0.75**	$0.98
Diluted	**$(0.77)**	$(0.62)	**$0.75**	$0.98

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

B) Dividends Per Share

For the three months ended December 31, 2015, the Company paid dividends of $0.16 per share (three months ended December 31, 2014 – $0.2662 per share). For the year ended December 31, 2015, the Company paid dividends of $710 million, including cash dividends of $528 million (year ended December 31, 2014 – $805 million, all of which was paid in cash). The Cenovus Board of Directors declared a first quarter dividend of $0.05 per share, payable on March 31, 2016, to common shareholders of record as of March 15, 2016. While the dividend reinvestment plan ("DRIP") remains in place, the discount has been discontinued.

10. INVENTORIES

As at	December 31, 2015	December 31, 2014
Product		
Refining and Marketing	**591**	972
Oil Sands	**158**	182
Conventional	**11**	28
Parts and Supplies	**50**	42
	810	1,224

As a result of a decline in commodity prices, Cenovus recorded a write-down of its product inventory of $66 million from cost to net realizable value as at December 31, 2015 (December 31, 2014 – $131 million).

11. EXPLORATION AND EVALUATION ASSETS

COST	
As at December 31, 2013	1,473
Additions	279
Transfers to PP&E (Note 12)	(53)
Exploration Expense (Note 7)	(86)
Divestitures	(2)
Change in Decommissioning Liabilities	14
As at December 31, 2014	1,625
Additions	138
Acquisition	3
Transfers to PP&E (Note 12)	(49)
Exploration Expense (Note 7)	(138)
Change in Decommissioning Liabilities	(4)
As at December 31, 2015	**1,575**

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

12. 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	2,522	43	162	63	2,790
Transfers From E&E Assets (Note 11)	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	1,289	2	240	45	1,576
Acquisition (Note 13)	1	-	-	83	84
Transfers From E&E Assets (Note 11)	49	-	-	-	49
Change in Decommissioning Liabilities	(635)	-	1	(1)	(635)
Exchange Rate Movements and Other	(1)	-	814	-	813
Divestitures	(923)	-	-	-	(923)
As at December 31, 2015	**31,481**	**331**	**5,206**	**1,037**	**38,055**
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 (Note 7)	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	1,601	44	189	80	1,914
Impairment Losses (Note 7)	200	-	-	-	200
Exchange Rate Movements and Other	(1)	-	123	1	123
Divestitures	(45)	-	-	-	(45)
As at December 31, 2015	**18,908**	**277**	**896**	**639**	**20,720**
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 December 31, 2015	**12,573**	**54**	**4,310**	**398**	**17,335**

(1) Includes crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft.

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

As at	**December 31, 2015**	December 31, 2014
Development and Production	**537**	478
Refining Equipment	**265**	159
	802	637

13. ACQUISITION

On August 31, 2015, the Company completed the acquisition of a crude-by-rail terminal for cash consideration of $75 million, plus adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with the acquisition, the Company assumed an associated decommissioning liability of $4 million, working capital of $1 million and net transportation commitments of $92 million. Transaction costs associated with the acquisition have been expensed. These assets and results of operations are reported in the Refining and Marketing segment.

14. GOODWILL

As at	December 31, 2015	December 31, 2014
Carrying Value, Beginning of Year	242	739
Impairment Losses (Note 7)	-	(497)
Carrying Value, End of Year	**242**	242

All of the Company's goodwill arose in 2002 upon the formation of the predecessor corporation. As at December 31, 2015 and 2014, the carrying amount of goodwill was associated with the Company's Primrose (Foster Creek) CGU.

15. LONG-TERM DEBT

As at	US$ Principal	December 31, 2015	December 31, 2014
Revolving Term Debt (1)	-	-	-
U.S. Dollar Denominated Unsecured Notes	4,750	6,574	5,510
Total Debt Principal		**6,574**	5,510
Debt Discounts and Transaction Costs		(49)	(52)
		6,525	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 of 2015, 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 December 31, 2015, the Company had $4.0 billion available on its committed credit facility.

As at December 31, 2015, the Company is in compliance with all of the terms of its debt agreements.

16. 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, refining facilities and the crude-by-rail terminal. The aggregate carrying amount of the obligation is:

As at	**December 31, 2015**	December 31, 2014
Decommissioning Liabilities, Beginning of Year	**2,616**	2,370
Liabilities Incurred	**10**	48
Liabilities Acquired	**4**	-
Liabilities Settled	**(62)**	(93)
Liabilities Divested	**-**	(60)
Transfers and Reclassifications	**-**	(9)
Change in Estimated Future Cash Flows	**(70)**	115
Change in Discount Rate	**(579)**	122
Unwinding of Discount on Decommissioning Liabilities	**126**	120
Foreign Currency Translation	**7**	3
Decommissioning Liabilities, End of Year	**2,052**	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 6.4 percent as at December 31, 2015 (December 31, 2014 – 4.9 percent).

17. 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

	December 31, 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 Year	**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 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. During the year ended December 31, 2015, the Company issued 8.7 million common shares from treasury under the DRIP.

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

As at December 31, 2015, there were 12 million (December 31, 2014 – 13 million) common shares available for future issuance under the stock option plan.

18. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Financial Assets	Total
As at December 31, 2013	(12)	212	10	210
Other Comprehensive Income (Loss), Before Tax	(24)	215	-	191
Income Tax	6	-	-	6
As at December 31, 2014	(30)	427	10	407
Other Comprehensive Income (Loss), Before Tax	28	587	8	623
Income Tax	(8)	-	(2)	(10)
As at December 31, 2015	**(10)**	**1,014**	**16**	**1,020**

19. TERMINATION BENEFITS

In response to the low-price environment and to align with the Company's more moderate growth plan, the Company reduced its workforce in 2015. Employee termination benefits of $31 million and $43 million were recorded as incurred in the three and twelve months ended December 31, 2015, respectively.

20. 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 December 31, 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**	**4.33**	**31.65**	**17.50**	**42,114**
TSARs	On or After February 17, 2010	**7**	**1.19**	**26.72**	**17.50**	**3,645**

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 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 December 31, 2015	Number of NSRs (Thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**40,549**	**32.63**
Granted	**4,106**	**22.25**
Exercised	**-**	**-**
Forfeited	**(2,541)**	**32.19**
Outstanding, End of Year	**42,114**	**31.65**
Exercisable, End of Year	**23,484**	**34.46**

TSARs

The Company has recorded a liability of $1 million as at December 31, 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 December 31, 2015 was $nil (December 31, 2014 – $nil).

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

As at December 31, 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	(144)	27.06
Expired	(73)	25.89
Outstanding, End of Year	3,645	26.72
Exercisable, End of Year	3,645	26.72

B) Performance Share Units

The Company has recorded a liability of $49 million as at December 31, 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 December 31, 2015. As PSUs are paid out upon vesting, the intrinsic value of vested PSUs was $nil as at December 31, 2015 and December 31, 2014.

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

As at December 31, 2015	Number of PSUs (Thousands)
Outstanding, Beginning of Year	7,099
Granted	2,909
Vested and Paid Out	(2,176)
Cancelled	(1,681)
Units in Lieu of Dividends	276
Outstanding, End of Year	6,427

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 $11 million as at December 31, 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 December 31, 2015. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at December 31, 2015 and December 31, 2014.

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

As at December 31, 2015	Number of RSUs (Thousands)
Outstanding, Beginning of Year	93
Granted	2,345
Vested and Paid Out	(22)
Cancelled	(251)
Units in Lieu of Dividends	102
Outstanding, End of Year	2,267

D) Deferred Share Units

The Company has recorded a liability of $26 million as at December 31, 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 December 31, 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 December 31, 2015	**Number of DSUs** (Thousands)
Outstanding, Beginning of Year	**1,297**
Granted to Directors	**68**
Granted	**68**
Units in Lieu of Dividends	**60**
Redeemed	**(5)**
Outstanding, End of Year	**1,488**

E) Total Stock-Based Compensation Expense (Recovery)

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

	Three Months Ended		**Twelve Months Ended**	
For the periods ended December 31,	**2015**	2014	**2015**	2014
NSRs	**7**	8	**27**	41
TSARs	**(1)**	(7)	**(5)**	(10)
PSUs	**(6)**	(15)	**(13)**	34
RSUs	**1**	-	**6**	-
DSUs	**(4)**	(7)	**(5)**	(5)
Stock-Based Compensation Expense (Recovery)	**(3)**	(21)	**10**	60

21. 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. 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. 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.

Over the long term, Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times. At different points within the economic cycle, Cenovus expects these ratios may periodically be outside of the target range.

A) Debt to Capitalization and Net Debt to Capitalization

As at	December 31, 2015	December 31, 2014
Debt	**6,525**	5,458
Add (Deduct):		
Cash and Cash Equivalents	**(4,105)**	(883)
Net Debt	**2,420**	4,575
Debt	**6,525**	5,458
Shareholders' Equity	**12,391**	10,186
	18,916	15,644
Debt to Capitalization	**34%**	35%
Net Debt	**2,420**	4,575
Shareholders' Equity	**12,391**	10,186
	14,811	14,761
Net Debt to Capitalization	**16%**	31%

B) Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA

As at	December 31, 2015	December 31, 2014
Debt	**6,525**	5,458
Net Debt	**2,420**	4,575
Net Earnings	**618**	744
Add (Deduct):		
Finance Costs	**482**	445
Interest Income	**(28)**	(33)
Income Tax Expense (Recovery)	**(81)**	451
Depreciation, Depletion and Amortization	**2,114**	1,946
Goodwill Impairment	**-**	497
E&E Impairment	**138**	86
Unrealized (Gain) Loss on Risk Management	**195**	(596)
Foreign Exchange (Gain) Loss, Net	**1,036**	411
(Gain) Loss on Divestitures of Assets	**(2,392)**	(156)
Other (Income) Loss, Net	**2**	(4)
Adjusted EBITDA	**2,084**	3,791
Debt to Adjusted EBITDA	**3.1x**	1.4x
Net Debt to Adjusted EBITDA	**1.2x**	1.2x

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, among other actions, 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.

As at December 31, 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.

Under the committed credit facility, the Company is required to maintain a debt to capitalization ratio, not to exceed 65 percent. The Company is well below this limit.

As at December 31, 2015, Cenovus is in compliance with all of the terms of its debt agreements.

22. 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, available for sale financial assets, 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 December 31, 2015, the carrying value of Cenovus's long-term debt was $6,525 million and the fair value was $6,050 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. The following table provides a reconciliation of changes in the fair value of available for sale financial assets:

As at	**December 31, 2015**	December 31, 2014
Fair Value, Beginning of Year	**32**	32
Acquisition of Investments	**2**	4
Reclassification of Equity Investments	**-**	(4)
Change in Fair Value (1)	**8**	-
Fair Value, End of Year	**42**	32

(1) Unrealized gains and losses on available for sale financial assets are recorded in other comprehensive income.

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, condensate, natural gas and power purchase contracts, as well as interest rate swaps. Crude oil, condensate 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 December 31, 2015 range from $30.00 to $41.00 per megawatt hour. The fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including quoted market prices and interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	December 31, 2015			December 31, 2014		
	Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**301**	**15**	**286**	423	7	416
Natural Gas	**-**	**-**	**-**	55	-	55
Power	**-**	**13**	**(13)**	-	9	(9)
	301	**28**	**273**	478	16	462
Interest Rate	**-**	**2**	**(2)**	-	-	-
Total Fair Value	**301**	**30**	**271**	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	**December 31, 2015**	December 31, 2014
Prices Sourced From Observable Data or Market Corroboration (Level 2)	**284**	471
Prices Determined From Unobservable Inputs (Level 3)	**(13)**	(9)
	271	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 December 31:

	2015	2014
Fair Value of Contracts, Beginning of Year	**462**	(129)
Fair Value of Contracts Realized During the Year (1)	**(656)**	(66)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year (2)	**461**	662
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**4**	(5)
Fair Value of Contracts, End of Year	**271**	462

(1) Includes a realized loss of $10 million related to the power contracts (2014 – $4 million gain).
(2) Includes a decrease of $14 million related to the power contracts (2014 – $10 million decrease).

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

	Three Months Ended		**Twelve Months Ended**	
For the periods ended December 31,	**2015**	2014	**2015**	2014
Realized (Gain) Loss (1)	**(239)**	(151)	**(656)**	(66)
Unrealized (Gain) Loss (2)	**26**	(416)	**195**	(596)
(Gain) Loss on Risk Management	**(213)**	(567)	**(461)**	(662)

(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.

23. 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. To manage the Company's exposure to interest rate volatility, during the fourth quarter of 2015 the Company entered into interest rate swap contracts related to future debt issuances. As at December 31, 2015, the Company had a notional amount of US$300 million in forward swaps.

Net Fair Value of Risk Management Positions

As at December 31, 2015	Notional Volumes	Terms	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	17,000 bbls/d	January – June 2016	$75.80/bbl	**64**
Brent Fixed Price	33,000 bbls/d	January – June 2016	US$47.59/bbl	**65**
Brent Fixed Price	10,000 bbls/d	January – December 2016	US$66.93/bbl	**127**
Brent Fixed Price	5,000 bbls/d	July – December 2016	$75.46/bbl	**13**
WCS Differential (1)	31,600 bbls/d	January – December 2016	US$(13.96)/bbl	**(9)**
Brent Collars	10,000 bbls/d	July – December 2016	US$45.55 – US$56.55/bbl	**11**
Other Financial Positions (2)				**17**
Crude Oil Fair Value Position				**288**
Condensate Purchase Contracts				
Mont Belvieu Fixed Price	3,000 bbls/d	January – December 2016	US$39.20/bbl	**(2)**
Power Purchase Contracts				
Power Fair Value Position				**(13)**
Interest Rate Swaps				**(2)**

(1) Cenovus entered into fixed-price swaps to protect against widening light/heavy price differential for heavy crudes.
(2) Other financial positions are part of ongoing operations to market the Company's production.

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 or interest rates, with all other variables held constant. Management believes the price and interest rate fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices and interest rates on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax based on the risk management positions in place as follows:

Risk Management Positions in Place as at December 31, 2015

	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent and WTI Hedges	**(243)**	**245**
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	**80**	**(80)**
Condensate Commodity Price	± US$10 per bbl Applied to Condensate Hedges	**23**	**(23)**
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	**19**	**(19)**
Interest Rate Swaps	± 50 Basis Points	**38**	**(46)**

24. 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. In the third quarter of 2015, net transportation commitments of $92 million were assumed upon the acquisition of the Company's crude-by-rail terminal. The Company did not enter into any other new material contracts for the year ended December 31, 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					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Gross Sales										
Upstream	**4,739**	**1,002**	1,152	1,410	1,175	**8,261**	1,721	2,147	2,295	2,098
Refining and Marketing	**8,805**	**2,030**	2,242	2,437	2,096	**12,658**	2,773	3,144	3,483	3,258
Corporate and Eliminations	**(337)**	**(77)**	(86)	(68)	(106)	**(812)**	(156)	(197)	(218)	(241)
Less: Royalties	**143**	**31**	35	53	24	**465**	100	124	138	103
Revenues	**13,064**	**2,924**	3,273	3,726	3,141	**19,642**	4,238	4,970	5,422	5,012

Operating Cash Flow

	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids										
Foster Creek	**454**	**72**	168	130	84	**969**	227	298	230	214
Christina Lake	**592**	**118**	159	199	116	**1,054**	237	308	293	216
Conventional	**683**	**132**	163	223	165	**1,367**	272	353	391	351
Natural Gas	**307**	**69**	79	78	81	**556**	112	129	163	152
Other Upstream Operations	**18**	**6**	3	2	7	**18**	12	-	5	1
	2,054	**397**	572	632	453	**3,964**	860	1,088	1,082	934
Refining and Marketing	**385**	**(40)**	30	300	95	**215**	(323)	68	223	247
Operating Cash Flow [(1)] [(2)]	**2,439**	**357**	602	932	548	**4,179**	537	1,156	1,305	1,181

Cash Flow

	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Cash from Operating Activities	**1,474**	**322**	542	335	275	**3,526**	868	1,092	1,109	457
Deduct (Add Back):										
Net Change in Other Assets and Liabilities	**(107)**	**(26)**	(13)	(14)	(54)	**(135)**	(38)	(28)	(27)	(42)
Net Change in Non-Cash Working Capital	**(110)**	**73**	111	(128)	(166)	**182**	505	135	(53)	(405)
Cash Flow [(3)]	**1,691**	**275**	444	477	495	**3,479**	401	985	1,189	904
Per Share - Basic	**2.07**	**0.33**	0.53	0.58	0.64	**4.60**	0.53	1.30	1.57	1.20
- Diluted	**2.07**	**0.33**	0.53	0.58	0.64	**4.59**	0.53	1.30	1.57	1.19

Earnings

	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Operating Earnings (Loss) [(4)]	**(403)**	**(438)**	(28)	151	(88)	**633**	(590)	372	473	378
Per Share - Diluted	**(0.49)**	**(0.53)**	(0.03)	0.18	(0.11)	**0.84**	(0.78)	0.49	0.62	0.50
Net Earnings (Loss)	**618**	**(641)**	1,801	126	(668)	**744**	(472)	354	615	247
Per Share - Basic	**0.75**	**(0.77)**	2.16	0.15	(0.86)	**0.98**	(0.62)	0.47	0.81	0.33
- Diluted	**0.75**	**(0.77)**	2.16	0.15	(0.86)	**0.98**	(0.62)	0.47	0.81	0.33

Tax & Exchange Rates

	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Effective Tax Rates Using:										
Net Earnings [(5)]	**(15.1)%**					**37.7%**				
Operating Earnings, Excluding Divestitures	**32.4%**					**29.7%**				
Canadian Statutory Rate [(6)]	**26.1%**					**25.2%**				
U.S. Statutory Rate	**38.0%**					**38.1%**				
Foreign Exchange Rates *(US$ per C$1)*										
Average	**0.782**	**0.749**	0.764	0.813	0.806	**0.905**	0.881	0.918	0.917	0.906
Period End	**0.723**	**0.723**	0.747	0.802	0.789	**0.862**	0.862	0.892	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) For all periods presented, employee long-term incentive costs were reclassified from operating expenses to general and administrative costs. There were no changes to Cash Flow, Operating Earnings or Net Earnings.

(3) 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.

(4) 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 and the recognition of an increase in U.S. tax basis.

(5) The 2015 effective tax rate reflects an increase to the tax basis of Cenovus's U.S. assets, the two percent increase in the Alberta corporate income tax rate and the benefit from recognition of previously unrecognized capital losses.

(6) 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					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Net Debt to Capitalization [(1)] [(2)]	**16%**	**16%**	13%	28%	27%	**31%**	31%	28%	30%	32%
Debt to Capitalization [(3)] [(4)]	**34%**	**34%**	33%	35%	35%	**35%**	35%	33%	33%	36%
Net Debt to Adjusted EBITDA [(1)] [(5)]	**1.2x**	**1.2x**	0.8x	1.5x	1.3x	**1.2x**	1.2x	1.0x	1.1x	1.2x
Debt to Adjusted EBITDA [(3)] [(5)]	**3.1x**	**3.1x**	2.7x	2.1x	1.9x	**1.4x**	1.4x	1.3x	1.2x	1.4x
Return on Capital Employed [(6)]	**5%**	**5%**	6%	(3)%	0%	**6%**	6%	9%	9%	7%
Return on Common Equity [(7)]	**5%**	**5%**	7%	(6)%	(2)%	**7%**	7%	11%	12%	7%

(1) 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.

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

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

(4) Capitalization is a non-GAAP measure defined as 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					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*										
Period End	**833.3**	**833.3**	833.3	833.3	828.5	**757.1**	757.1	757.1	757.0	756.9
Average - Basic	**818.7**	**833.3**	833.3	828.6	778.9	**756.9**	757.1	757.1	756.9	756.4
Average - Diluted	**818.7**	**833.3**	833.3	828.6	778.9	**757.6**	757.1	758.8	758.0	757.3
Price Range *($ per share)*										
TSX - C$										
High	**26.42**	**22.35**	20.91	24.28	26.42	**34.79**	30.13	34.79	34.70	32.02
Low	**15.75**	**16.85**	15.75	19.53	20.45	**18.72**	18.72	29.77	30.80	28.25
Close	**17.50**	**17.50**	20.24	19.98	21.35	**23.97**	23.97	30.13	34.59	31.97
NYSE - US$										
High	**21.12**	**17.23**	15.97	19.72	21.12	**32.64**	26.89	32.64	32.44	28.96
Low	**11.85**	**12.10**	11.85	15.69	16.29	**16.11**	16.11	26.57	28.35	25.52
Close	**12.62**	**12.62**	15.16	16.01	16.88	**20.62**	20.62	26.88	32.37	28.96
Dividends *($ per share)*	**0.8524**	**0.1600**	0.1600	0.2662	0.2662	**1.0648**	0.2662	0.2662	0.2662	0.2662
Share Volume Traded *(millions)*	**1,691.2**	**377.1**	483.3	388.7	442.1	**803.8**	333.1	147.7	152.7	170.3

Net Capital Investment

	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Capital Investment *($ millions)*										
Oil Sands										
Foster Creek	**403**	**85**	96	73	149	**796**	159	207	209	221
Christina Lake	**647**	**132**	147	161	207	**794**	231	198	183	182
Total	**1,050**	**217**	243	234	356	**1,590**	390	405	392	403
Other Oil Sands	**135**	**22**	29	26	58	**396**	104	89	79	124
	1,185	**239**	272	260	414	**1,986**	494	494	471	527
Conventional	**244**	**87**	55	36	66	**840**	219	198	153	270
Refining and Marketing	**248**	**89**	67	48	44	**163**	52	42	46	23
Corporate	**37**	**13**	6	13	5	**62**	21	16	16	9
Capital Investment	**1,714**	**428**	400	357	529	**3,051**	786	750	686	829
Acquisitions [(1)]	**87**	**3**	84	-	-	**18**	1	-	16	1
Divestitures	**(3,344)**	**1**	(3,329)	-	(16)	**(277)**	(1)	(235)	(39)	(2)
Net Acquisition and Divestiture Activity	**(3,257)**	**4**	(3,245)	-	(16)	**(259)**	-	(235)	(23)	(1)
Net Capital Investment	**(1,543)**	**432**	(2,845)	357	513	**2,792**	786	515	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					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*										
Oil Sands										
Foster Creek	**65,345**	**63,680**	71,414	58,363	67,901	**59,172**	68,377	56,631	56,852	54,706
Christina Lake	**74,975**	**75,733**	75,329	72,371	76,471	**69,023**	73,836	68,458	67,975	65,738
	140,320	**139,413**	146,743	130,734	144,372	**128,195**	142,213	125,089	124,827	120,444
Conventional										
Heavy Oil	**34,888**	**32,363**	33,997	36,099	37,155	**39,546**	38,021	39,096	40,304	40,799
Light and Medium Oil	**30,486**	**26,625**	28,491	31,809	35,135	**34,531**	34,661	33,548	35,329	34,598
Natural Gas Liquids [(1)]	**1,253**	**1,155**	1,191	1,312	1,358	**1,221**	1,282	1,356	1,228	1,013
	66,627	**60,143**	63,679	69,220	73,648	**75,298**	73,964	74,000	76,861	76,410
Total Crude Oil and Natural Gas Liquids	**206,947**	**199,556**	210,422	199,954	218,020	**203,493**	216,177	199,089	201,688	196,854
Natural Gas *(MMcf/d)*										
Oil Sands	**19**	**19**	19	21	20	**22**	22	23	23	19
Conventional	**422**	**405**	411	429	442	**466**	457	466	484	457
Total Natural Gas	**441**	**424**	430	450	462	**488**	479	489	507	476
Total Production *(BOE/d)*	**280,447**	**270,223**	282,089	274,954	295,020	**284,826**	296,010	280,589	286,188	276,187

(1) Natural gas liquids include condensate volumes.

Average Royalty Rates
(Excluding Impact of Realized Gain (Loss) on Risk Management)

	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek [(1)]	**1.9%**	**0.7%**	0.8%	5.0%	(1.2)%	**8.8%**	11.2%	7.2%	9.3%	8.1%
Christina Lake	**2.8%**	**1.9%**	3.7%	2.5%	3.1%	**7.5%**	7.2%	7.9%	7.7%	7.1%
Conventional										
Pelican Lake	**9.0%**	**8.1%**	4.7%	14.3%	6.0%	**7.5%**	8.4%	7.1%	8.0%	6.9%
Weyburn	**17.7%**	**17.0%**	18.7%	18.4%	16.5%	**21.9%**	19.0%	24.0%	24.4%	19.4%
Other	**5.2%**	**12.2%**	8.2%	1.2%	3.5%	**5.9%**	6.7%	6.5%	5.5%	4.9%
Natural Gas Liquids	**5.6%**	**12.8%**	7.1%	2.2%	2.3%	**2.1%**	2.6%	1.6%	2.2%	2.2%
Natural Gas	**2.5%**	**3.8%**	3.7%	1.2%	1.6%	**1.9%**	2.5%	2.0%	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 3.1 percent, respectively.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Refining	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Refinery Operations [1]										
Crude Oil Capacity *(Mbbls/d)*	**460**	**460**	460	460	460	**460**	460	460	460	460
Crude Oil Runs *(Mbbls/d)*	**419**	**405**	394	441	439	**423**	420	407	466	400
Heavy Oil	**200**	**196**	186	200	220	**199**	179	201	221	195
Light/Medium	**219**	**209**	208	241	219	**224**	241	206	245	205
Crude Utilization	**91%**	**88%**	86%	96%	95%	**92%**	91%	88%	101%	87%
Refined Products *(Mbbls/d)*	**444**	**430**	414	462	469	**445**	442	429	489	420

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

Selected Average Benchmark Prices	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
Brent	**53.64**	**44.71**	51.17	63.50	55.17	**99.51**	76.98	103.39	109.77	107.90
West Texas Intermediate ("WTI")	**48.80**	**42.18**	46.43	57.94	48.63	**93.00**	73.15	97.17	102.99	98.68
Differential Brent - WTI	**4.84**	**2.53**	4.74	5.56	6.54	**6.51**	3.83	6.22	6.78	9.22
Western Canadian Select ("WCS")	**35.28**	**27.69**	33.16	46.35	33.90	**73.60**	58.91	76.99	82.95	75.55
Differential WTI - WCS	**13.52**	**14.49**	13.27	11.59	14.73	**19.40**	14.24	20.18	20.04	23.13
Condensate (C5 @ Edmonton)	**47.36**	**41.67**	44.21	57.94	45.62	**92.95**	70.57	93.45	105.15	102.64
Differential WTI - Condensate (Premium)/Discount	**1.44**	**0.51**	2.22	-	3.01	**0.05**	2.58	3.72	(2.16)	(3.96)
Refining Margins 3-2-1 Crack Spreads [1] *(US$/bbl)*										
Chicago	**19.11**	**14.47**	24.67	20.77	16.53	**17.61**	14.60	17.57	19.72	18.55
Group 3	**18.16**	**13.82**	22.03	19.34	17.46	**16.27**	13.28	16.65	17.75	17.41
Natural Gas Prices										
AECO *(C$/Mcf)*	**2.77**	**2.65**	2.80	2.67	2.95	**4.42**	4.01	4.22	4.67	4.76
NYMEX *(US$/Mcf)*	**2.66**	**2.27**	2.77	2.64	2.98	**4.42**	4.00	4.06	4.67	4.94
Differential NYMEX - AECO *(US$/Mcf)*	**0.49**	**0.27**	0.61	0.50	0.57	**0.40**	0.44	0.16	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	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Heavy Oil - Foster Creek [1] [2] *($/bbl)*										
Price	**33.65**	**25.09**	33.35	48.25	29.42	**69.43**	51.95	76.82	79.77	71.44
Royalties	**0.47**	**0.12**	0.20	1.97	(0.25)	**5.95**	5.67	5.40	7.14	5.71
Transportation and Blending	**8.84**	**8.53**	8.50	9.04	9.39	**1.98**	1.85	2.17	3.10	0.78
Operating [3]	**12.60**	**11.66**	11.27	13.29	14.50	**16.35**	13.73	14.67	18.90	18.72
Netback	**11.74**	**4.78**	13.38	23.95	5.78	**45.15**	30.70	54.58	50.63	46.23
Heavy Oil - Christina Lake [1] [2] *($/bbl)*										
Price	**28.45**	**21.34**	27.46	43.36	23.30	**61.57**	47.21	67.62	72.25	59.89
Royalties	**0.67**	**0.30**	0.83	0.99	0.61	**4.40**	3.14	5.07	5.37	4.04
Transportation and Blending	**4.72**	**5.40**	5.00	4.29	4.17	**3.53**	4.14	3.75	3.14	3.02
Operating [3]	**8.01**	**7.80**	7.80	8.20	8.24	**11.09**	9.34	10.34	11.85	13.12
Netback	**15.05**	**7.84**	13.83	29.88	10.28	**42.55**	30.59	48.46	51.89	39.71
Total Heavy Oil - Oil Sands [1] [2] *($/bbl)*										
Price	**30.88**	**23.08**	30.35	45.61	26.04	**65.18**	49.44	71.82	75.65	65.19
Royalties	**0.58**	**0.22**	0.52	1.44	0.22	**5.11**	4.33	5.22	6.17	4.80
Transportation and Blending	**6.64**	**6.85**	6.72	6.48	6.50	**2.82**	3.06	3.03	3.12	1.99
Operating [3]	**10.13**	**9.59**	9.46	10.57	10.99	**13.50**	11.41	12.32	14.98	15.72
Netback	**13.53**	**6.42**	13.65	27.12	8.33	**43.75**	30.64	51.25	51.38	42.68
Heavy Oil - Conventional [1] [2] *($/bbl)*										
Price	**39.95**	**32.84**	37.09	52.63	35.85	**76.25**	60.25	81.30	83.29	78.52
Royalties	**2.97**	**2.24**	1.73	5.34	2.34	**7.09**	6.85	7.72	7.76	6.01
Transportation and Blending	**3.36**	**3.63**	3.36	3.09	3.42	**3.29**	3.22	3.40	3.44	3.09
Operating [3]	**15.92**	**15.20**	15.59	15.45	17.30	**20.51**	18.41	19.94	20.27	23.16
Production and Mineral Taxes	**0.04**	**(0.03)**	0.07	0.08	0.02	**0.18**	0.03	0.24	0.32	0.13
Netback	**17.66**	**11.80**	16.34	28.67	12.77	**45.18**	31.74	50.00	51.50	46.13
Total Heavy Oil [1] [2] *($/bbl)*										
Price	**32.73**	**24.87**	31.63	47.24	28.15	**67.83**	51.74	73.99	77.63	68.64
Royalties	**1.07**	**0.59**	0.75	2.35	0.68	**5.59**	4.87	5.79	6.58	5.12
Transportation and Blending	**5.97**	**6.26**	6.08	5.69	5.83	**2.93**	3.09	3.11	3.20	2.28
Operating [3]	**11.31**	**10.62**	10.62	11.70	12.35	**15.18**	12.90	14.06	16.35	17.65
Production and Mineral Taxes	**0.01**	**(0.01)**	0.01	0.02	-	**0.04**	0.01	0.05	0.08	0.03
Netback	**14.37**	**7.41**	14.17	27.48	9.29	**44.09**	30.87	50.98	51.42	43.56

(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	**27.44**	**25.96**	24.20	29.82	30.57	**42.01**	35.45	38.50	47.28	48.35
Christina Lake	**29.50**	**27.39**	26.42	32.90	31.60	**45.45**	38.23	42.57	49.30	52.81
Heavy Oil - Oil Sands	**28.54**	**26.72**	25.33	31.48	31.14	**43.87**	36.92	40.71	48.39	50.77
Heavy Oil - Conventional	**10.94**	**9.99**	9.56	12.42	11.50	**15.71**	13.98	13.25	17.70	17.56
Total Heavy Oil	**24.94**	**23.64**	22.34	27.06	26.91	**37.13**	32.04	34.42	40.44	42.17

(3) For all periods presented, employee long-term incentive costs were reclassified from operating expenses to general and administrative costs.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Per-unit Results

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

	2015					2014				
	Year	**Q4**	Q3	Q2	Q1	**Year**	Q4	Q3	Q2	Q1
Light and Medium Oil *($/bbl)*										
Price	**50.64**	**45.35**	49.57	61.66	45.81	**88.30**	71.10	89.85	98.27	94.18
Royalties	**5.66**	**6.97**	7.02	5.67	3.56	**9.15**	6.12	10.36	11.37	8.78
Transportation and Blending	**2.91**	**2.80**	2.88	3.06	2.88	**3.34**	2.89	3.06	3.31	4.11
Operating [1]	**16.27**	**17.37**	15.92	15.90	16.04	**16.98**	16.06	17.23	16.75	17.94
Production and Mineral Taxes	**1.41**	**0.76**	1.60	1.95	1.28	**2.70**	2.59	2.99	2.97	2.23
Netback	**24.39**	**17.45**	22.15	35.08	22.05	**56.13**	43.44	56.21	63.87	61.12
Total Crude Oil [2] *($/bbl)*										
Price	**35.41**	**27.62**	34.08	49.55	31.09	**71.39**	55.05	76.64	81.35	73.15
Royalties	**1.75**	**1.44**	1.60	2.88	1.16	**6.21**	5.08	6.56	7.45	5.76
Transportation and Blending	**5.51**	**5.79**	5.64	5.27	5.34	**3.00**	3.06	3.10	3.22	2.60
Operating [1]	**12.05**	**11.52**	11.35	12.37	12.97	**15.49**	13.44	14.59	16.42	17.70
Production and Mineral Taxes	**0.22**	**0.10**	0.23	0.33	0.22	**0.50**	0.45	0.54	0.60	0.42
Netback	**15.88**	**8.77**	15.26	28.70	11.40	**46.19**	33.02	51.85	53.66	46.67
Natural Gas Liquids *($/bbl)*										
Price	**30.98**	**30.70**	24.57	39.64	28.51	**65.55**	50.82	66.70	78.38	67.31
Royalties	**1.74**	**3.94**	1.75	0.87	0.66	**1.38**	1.34	1.07	1.70	1.48
Netback	**29.24**	**26.76**	22.82	38.77	27.85	**64.17**	49.48	65.63	76.68	65.83
Total Liquids [2] *($/bbl)*										
Price	**35.38**	**27.63**	34.03	49.48	31.08	**71.35**	55.02	76.57	81.33	73.12
Royalties	**1.75**	**1.46**	1.60	2.86	1.16	**6.18**	5.06	6.52	7.41	5.74
Transportation and Blending	**5.48**	**5.76**	5.61	5.24	5.31	**2.98**	3.04	3.08	3.20	2.59
Operating [1]	**11.98**	**11.46**	11.28	12.29	12.89	**15.40**	13.36	14.50	16.32	17.61
Production and Mineral Taxes	**0.22**	**0.10**	0.23	0.33	0.22	**0.50**	0.44	0.54	0.60	0.42
Netback	**15.95**	**8.85**	15.31	28.76	11.50	**46.29**	33.12	51.93	53.80	46.76
Total Natural Gas *($/Mcf)*										
Price	**2.92**	**2.78**	3.00	2.82	3.05	**4.37**	3.89	4.22	4.87	4.47
Royalties	**0.07**	**0.10**	0.11	0.03	0.05	**0.08**	0.09	0.08	0.09	0.06
Transportation and Blending	**0.11**	**0.11**	0.10	0.10	0.12	**0.12**	0.13	0.11	0.11	0.11
Operating [1]	**1.20**	**1.25**	1.16	1.14	1.26	**1.22**	1.21	1.23	1.20	1.24
Production and Mineral Taxes	**0.01**	**0.02**	0.01	0.02	0.01	**0.05**	0.03	0.05	0.13	(0.01)
Netback	**1.53**	**1.30**	1.62	1.53	1.61	**2.90**	2.43	2.75	3.34	3.07
Total [2] [3] *($/BOE)*										
Price	**30.67**	**24.78**	29.95	40.50	27.73	**58.29**	46.14	61.85	65.71	59.68
Royalties	**1.40**	**1.23**	1.36	2.13	0.93	**4.53**	3.80	4.79	5.36	4.19
Transportation and Blending	**4.21**	**4.43**	4.35	3.95	4.11	**2.32**	2.40	2.39	2.45	2.03
Operating [1]	**10.72**	**10.43**	10.18	10.78	11.49	**13.06**	11.66	12.45	13.59	14.65
Production and Mineral Taxes	**0.18**	**0.10**	0.19	0.27	0.17	**0.44**	0.36	0.48	0.65	0.28
Netback	**14.16**	**8.59**	13.87	23.37	11.03	**37.94**	27.92	41.74	43.66	38.53
Impact of Realized Gain (Loss) on Risk Management										
Liquids *($/bbl)*	**7.51**	**11.39**	10.07	1.75	6.58	**0.50**	7.06	(0.45)	(2.94)	(2.00)
Natural Gas *($/Mcf)*	**0.37**	**0.42**	0.37	0.39	0.29	**0.04**	0.05	0.11	(0.02)	-
Total [3] *($/BOE)*	**6.11**	**9.08**	8.07	1.92	5.31	**0.42**	5.17	(0.13)	(2.09)	(1.42)

(1) For all periods presented, employee long-term incentive costs were reclassified from operating expenses to general and administrative costs.

(2) The netbacks do not reflect non-cash write-downs of product inventory.

(3) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (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.