cenovus ENERGY

2015 ANNUAL REPORT

Cenovus is a Canadian integrated oil company. This is our Christina Lake oil sands project located about 150 kilometres south of Fort McMurray, Alberta. We're always working to decrease the amount of land we use for our operations, which is good for our bottom line and the environment. Once we're finished producing oil at Christina Lake we will reclaim all the land.

WHY WE EXIST (OUR PURPOSE)

To fuel world progress

WHAT WE DO (OUR PROMISE)

To create value by responsibly providing energy the world wants

WHAT WE'RE COMMITTED TO

- Working safely
- Operating in a way that maintains and enhances our reputation
- Making smart environmental choices every day
- Strengthening the communities where we live and work
- Having an engaging workplace

WHAT DIFFERENTIATES US

- Premium asset quality
- Disciplined manufacturing
- Focused innovation
- Value-added integration
- Trusted reputation

ON THE COVER

The picture on the cover shows Reed, a worker at our Christina Lake oil sands project, walking in front of two of our water tanks. Those tanks are also shown in the picture on the right. At Cenovus, we don't mine the oil sands. We drill into our reservoirs, which are deep underground, and use steam to melt the thick oil so it can be pumped to the surface. When the water and oil reach the surface, they're separated. The oil is transported to refineries where it's made into usable products and the water is sent to these tanks for temporary storage until it's recycled and made into steam again. Each water tank holds more than three million litres of water. Almost all of the water we use to make the steam is drawn from underground aquifers and is too salty for consumption or for agriculture.

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For additional information about the forward-looking statements, non-GAAP measures, and reserves and resources estimates contained in this annual report, see the Advisory on page 98.

MESSAGE FROM OUR

PRESIDENT & CHIEF EXECUTIVE OFFICER

March, 2016 – Looking back on 2015, I can tell you this has been the most challenging business environment I have experienced in my 35-year career. Our industry has been affected by a prolonged period of low oil prices, continued market volatility and political changes both federally and provincially.

My primary objective for the year was to ensure our financial resilience without compromising Cenovus's future and that remains my objective today. Well before the drop in oil prices, we were working hard to make Cenovus a better, stronger and more financially resilient company for you, our shareholders. We were focused on improving our position as a low-cost producer, strengthening our balance sheet and finding ways to get global prices for our oil.

Thanks to the hard work and determination of our staff, and the difficult but critical actions we undertook in 2015, we entered 2016 in an even stronger financial position than we were a year earlier.

In 2015, we delivered on what was within our control. We had our best workplace safety performance since we became a company in 2009. We made substantial, sustainable cost reductions and maintained capital discipline, and we reduced our oil sands operating costs by 25 percent while achieving oil sands production growth.

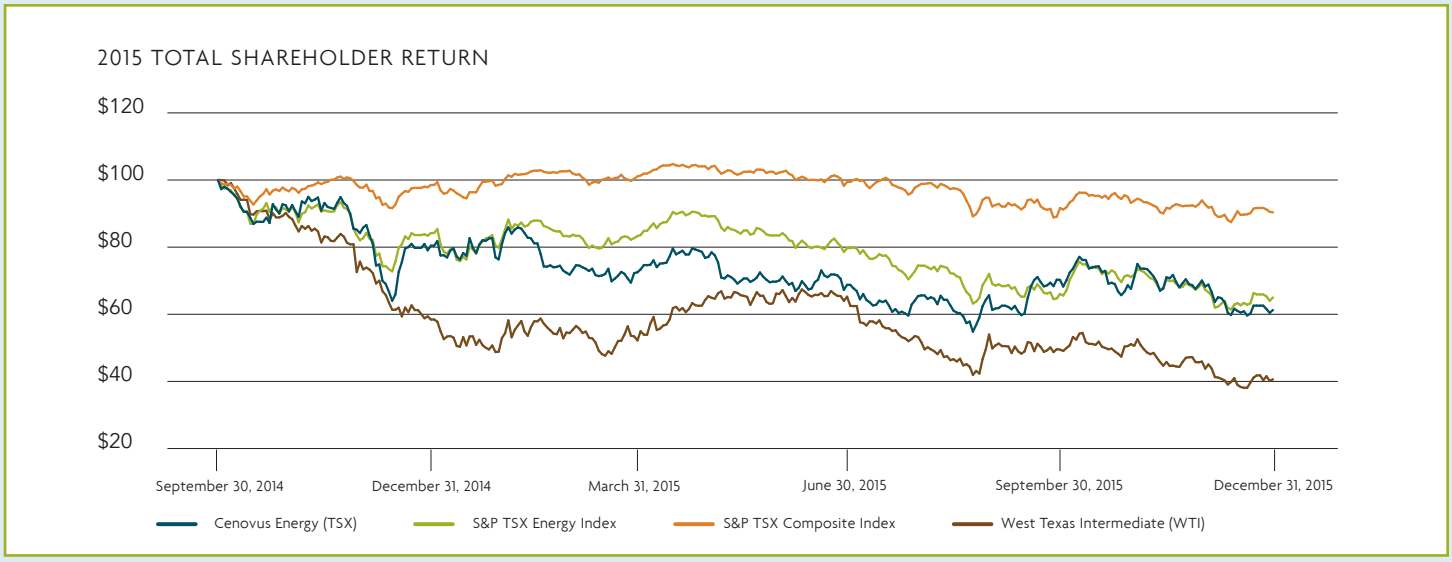
Given the worsening business climate in early 2016, we have already undertaken further necessary decisive actions to help preserve our financial resilience so we can maintain the balance sheet strength we've worked so hard to achieve. We have also shifted to a more moderate and focused growth plan, to help ensure we are well-positioned for our new business reality – one that anticipates low oil prices to continue for the foreseeable future.

The measures we have implemented since the beginning of 2015 include:

- Completing a common share equity issue for net proceeds of $1.4 billion
- Selling our royalty and fee land business for cash proceeds of $3.3 billion
- Reducing our planned 2016 capital expenditures by 27 percent compared with 2015 spending and 59 percent compared with 2014
- Reducing oil sands non-fuel operating costs by 19 percent compared with 2014
- Reducing our workforce by 24 percent in 2015 with further reductions planned in 2016, and adjusting compensation, time-off practices and other employee benefits and programs
- Reducing our dividend by 40 percent in 2015, and reducing it by another 69 percent in early 2016

It would be remiss of me to not acknowledge that those actions have also changed Cenovus. It is why the Leadership Team and I have been working to evolve our company. As part of the evolution, we have defined what kind of company Cenovus needs to be for continued success. We have clarified our strategy. We have outlined the culture and behaviours that are important to us. And we are transitioning to a new organizational structure. We have made these necessary changes to position Cenovus to become a low-cost producer that can compete with any oil producer across North America. With the strength of our balance sheet, and the evolution of our company underway, we can turn our minds to the future and build on our accomplishments.

Our strong balance sheet provides us with the flexibility to make counter-cyclical investments to grow our business when we feel the time is right. We have multiple years'



Total shareholder return and share prices for Cenovus and our peers continued to be significantly impacted by the 59 percent reduction in WTI crude oil prices since September of 2014. For Cenovus, total shareholder return from September 2014 to December 2015 was negative 39 percent. We were in line with the TSX Energy Index, which was down 35 percent in the same time period, but underperformed the TSX Composite Index which only fell by 10 percent.

worth of investment opportunities through our portfolio of regulatory-approved projects, including the phase H expansion at our Christina Lake oil sands project which was approved in late 2015. We have some of the best oil sands assets in the industry, but we will not continue to add new phases just for the sake of growth. Production must be linked to value creation. Advancing the development plan for these approved projects will depend on our ability to continue reducing our costs, and we will only advance them if we think we can ensure balance sheet strength while doing so.

Our marketing and transportation strategy positions Cenovus to maximize value for every barrel of oil we produce. We take an integrated approach to production, transportation and refining in order to capture the best prices for our oil. As part of our plan to build a portfolio of transportation options, we purchased a crude-by-rail terminal in Bruderheim, Alberta in 2015. We remain focused on finding new customers around the world in order to receive the best prices, and on ensuring our ability to move our oil to those customers. We are also working to create a variety of oil blends that we expect will help maximize our transportation and refining options.

The Government of Alberta's climate plan was an important announcement for our industry in 2015. I believe this climate policy is the right one for Cenovus, for our industry, for Albertans and for all Canadians. It sets the stage for Alberta to become a leader in low-carbon technology. And it bolsters Alberta's reputation as an innovative and collaborative place to do business. The new policy offers greater predictability for businesses, sharpens Alberta's position as a global competitor and could open new markets for our production.

It is no longer enough for fossil fuel companies to strive to achieve the lowest costs. They must also compete to be the lowest carbon producer. At Cenovus, we share the public's concern that climate change is one of the greatest global challenges of our time.

As an oil producer, we are committed to doing our part to address climate change and find innovative solutions that will reduce and potentially eliminate emissions both from the production of oil and from its use. With the right level of commitment and collaboration with the brightest minds from around the world, I believe oil can be part of the clean energy future we all desire.

I want to take a moment to thank the members of Cenovus's Leadership Team and Board and welcome five new Leadership Team members as well as Steven Leer who joined the Board in 2015. There will be further changes to our Board in the coming year as Ralph Cunningham will retire in 2016. A very special thank you to Ralph as well as to the Leadership Team members who have retired – John Brannan, Kerry Dyte, Sheila McIntosh and Hayward Walls. Their contributions and guidance over the years have been invaluable and I wish them all the best in their retirement.

Also, I want to thank everyone at Cenovus for their ongoing hard work and commitment during a very difficult time for our industry. Thanks to their tremendous efforts, we are well-positioned for success in 2016 and beyond. Our direction is clear, we are confident in our strategy and we continue to take steps to help ensure we come out of this downturn as a stronger company.

I believe we are in a great position to create value for you, our shareholders, over the long term.

/s/ Brian C. Ferguson

BRIAN C. FERGUSON

President & Chief Executive Officer

MESSAGE FROM OUR

BOARD CHAIR

March, 2016 – Despite rapidly falling oil prices, Cenovus finished 2015 with substantial cash on hand and a much lower cost structure, prepared to face a prolonged period of significantly lower revenue and ready for the future. Your Board believes you should be, and hopes that you are, very pleased with how your company responded to challenges faced during the year.

In January of 2015 the near-term outlook for the oil industry was uncertain, but decidedly negative. With no sign of improvement in sight, good governance and good management demanded that the organization embrace a sense of urgency and take action while maintaining a view to the longer term.

Cenovus was in an excellent position to do just that. Its beginning balance sheet was strong. Management had already been investigating ways to further strengthen the company's financial position and implement a cost reduction plan. Your Board's and Management's past experience included working through two or more previous periods of very low oil prices. Cenovus was as prepared as it could be for what was to come.

The first order of business was, and still is, to survive the downturn. With contingency plans already in place Cenovus was able to complete a large equity issue early in the year while capital markets were still receptive and complete a significant asset sale by mid-year while oil and gas properties were still attracting favourable prices. A cost reduction plan, which addressed both capital and operating costs, was in the early stage of implementation and readily accelerated. The combination of large cash infusions with significantly reduced spending rates made the company viable at much lower oil prices.

But we believe the true value of Cenovus lies in the future. So it was equally critical that the company follow its stated strategy as closely as possible. To that end, Management concentrated company resources on its near-term most valuable assets. They integrated cost consciousness into all of the company's everyday activities. They re-balanced the size and structure of the organization to match the current stage and pace of operations. They undertook a number of initiatives to improve market access. They continue to explore and invest in the application of new ideas and new technologies to both further reduce costs and further reduce the business's impact on the environment. These actions, together with substantial financial capacity, make it possible for Cenovus to not only survive, but to seize opportunities if, as and when they arise. All of these actions are future oriented and fully aligned with the Cenovus strategy.

This annual report describes performance supporting these statements and will hopefully lead you to conclude that your company is well managed, will emerge from this downturn fully prepared to prosper when conditions improve and is capable of realizing Cenovus's full potential for its shareholders.

Respectfully submitted on behalf of the Board,

/s/ Michael A. Grandin
MICHAEL A. GRANDIN
Board Chair

OUR

LEADERSHIP TEAM

Our Leadership Team guides our plans, prioritizes our initiatives and leads by example. Underpinning their strong leadership is a tremendous depth of talent and knowledge that will help position us to execute on our business plan. We had four Executive Vice-Presidents retire over the last year and we've welcomed the following new members to our Leadership Team – Judy Fairburn, Jacqui McGillivray, Al Reid and Drew Zieglgansberger. Joining the Leadership Team in April is Kieron McFadyen who will be our Executive Vice-President & President, Upstream Oil & Gas.

From left to right:

Al Reid Executive Vice-President, Environment, Corporate Affairs, Legal & General Counsel

Jacqui McGillivray Executive Vice-President, Safety & Organization Effectiveness

Brian Ferguson President & Chief Executive Officer

Robert Pease Executive Vice-President, Corporate Strategy & President, Downstream

Drew Zieglgansberger Executive Vice-President, Oil Sands Manufacturing

Judy Fairburn Executive Vice-President, Business Innovation

Ivor Ruste Executive Vice-President & Chief Financial Officer

Harbir Chhina Executive Vice-President, Oil Sands Development

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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated February 10, 2016, should be read in conjunction with our December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 10, 2016, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 10, 2016. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Financial Results or Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2015, we had a market capitalization of approximately $15 billion. We 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."). Our average crude oil and NGLs (collectively, "crude oil") production in 2015 was approximately 207,000 barrels per day and our average natural gas production was 441 MMcf per day. Our refineries processed an average of 419,000 gross barrels per day of crude oil feedstock into an average of 444,000 gross barrels per day of refined products.

Our Key Message for 2015

2015 was a challenging year for the oil and gas industry as the low commodity price environment prompted significant reductions in capital spending programs and extensive efforts to reduce costs. The deterioration of crude oil prices resulted in a significant decline in our cash flow and earnings.

During these volatile times, Cenovus has remained focused on delivering value through preserving financial resilience, achieving sustainable cost reductions and exercising capital discipline. Together, our common share issuance and the sale of our royalty interest and mineral fee title lands business raised cash proceeds of approximately $4.7 billion. These transactions significantly strengthened our balance sheet and our net debt to capitalization ratio was 16 percent at December 31, 2015. We also reduced our capital, operating and general and administrative spending, capturing savings of approximately $540 million, relative to our budget.

We expect commodity prices to remain low for the foreseeable future and continue to make adjustments to our capital spending and cost structure. For more information, we direct our readers to review the news release for our revised 2016 guidance dated February 11, 2016. The news release is available on our website at cenovus.com, on SEDAR at sedar.com and on EDGAR at sec.gov.

Our Strategy

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

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

- Our producing asset mix, including:
  - Oil sands for long-term growth;
  - Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
  - Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs.
- Our marketing, products and transportation activities, including:
  - Refining oil into various products to reduce the impact of commodity price fluctuations;
  - Creating a variety of oil blends to help maximize our transportation and refining options; and
  - Accessing new markets that will position us to achieve the best pricing for our oil.

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

Oil Development

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek and Christina Lake. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta, including Narrows Lake, Telephone Lake and Grand Rapids, as well as our conventional oil opportunities.

We are positioned to increase our annual net crude oil production, including our conventional crude oil operations, by fully developing our production projects and those that currently have regulatory approval.

Disciplined Manufacturing

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, positioning us to minimize costs. We continue to focus on executing our business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date. We are committed to developing our resources safely and responsibly.

Financial Strength

Maintaining a strong balance sheet is necessary to execute our strategy. We anticipate our total annual capital investment for 2016 to be between $1.2 billion and $1.3 billion. This is 27 percent lower than in 2015, reflecting moderate spending in response to the sustained low commodity price environment. At December 31, 2015, we had $4.1 billion of cash on hand, $4.0 billion of undrawn capacity on our committed credit facility, and no debt maturing until the fourth quarter of 2019. To help ensure our continued financial flexibility, we will pursue further cost reductions, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

Dividend

In 2015, we paid a dividend of $0.8524 per share compared with $1.0648 per share in 2014 (2013 – $0.968 per share). We reduced our dividend by 40 percent in the third quarter of 2015, from $0.2662 per share to $0.16 per share, as part of our strategy to maintain our long-term financial resilience. Our dividend was further reduced to $0.05 per share in the first quarter of 2016. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

Focused Innovation

Technology development, research activities and understanding our impact on the environment play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing technologies with a focus on increasing recoveries from our reservoirs, and improving cycle times, margins and environmental performance. We have a track record of developing innovative solutions that unlock challenging crude oil resources, building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Our Operations

Oil Sands

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

	2015		
	Ownership Interest (percent)	**Net Production Volumes** (bbls/d)	**Gross Production Volumes** (bbls/d)
Existing Projects			
Foster Creek	**50**	**65,345**	**130,690**
Christina Lake	**50**	**74,975**	**149,950**
Narrows Lake	**50**	**-**	**-**
Emerging Projects			
Telephone Lake	**100**	**-**	**-**
Grand Rapids	**100**	**-**	**-**

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. Foster Creek and Christina Lake are producing and Narrows Lake is in the initial stages of development. These projects are located in the Athabasca region of northeastern Alberta. Two of our 100 percent-owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions of northeastern Alberta, respectively.

	2015	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Cash Flow	**1,046**	**10**
Capital Investment	**1,184**	**1**
Operating Cash Flow Net of Related Capital Investment	**(138)**	**9**

Conventional

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

	2015	
($ millions)	**Crude Oil** [(1)]	**Natural Gas**
Operating Cash Flow	**683**	**297**
Capital Investment	**231**	**13**
Operating Cash Flow Net of Related Capital Investment	**452**	**284**

(1) Includes NGLs.

We have established crude oil and natural gas producing assets, including heavy oil assets at Pelican Lake, a carbon dioxide ("CO_2") enhanced oil recovery project in Weyburn, Saskatchewan, and emerging tight oil assets in Alberta.

Refining and Marketing

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

	2015	
	Ownership Interest (percent)	**Gross Nameplate Capacity** (Mbbls/d)
Wood River	**50**	**314**
Borger	**50**	**146**

Our refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American crude oil price differential fluctuations. This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	**2015**
Operating Cash Flow	**385**
Capital Investment	**248**
Operating Cash Flow Net of Related Capital Investment	**137**

2015 HIGHLIGHTS

In 2015, Cenovus delivered on the commitments we made to our shareholders. We met our production targets, achieved significant sustainable cost savings in all areas of our business and strengthened our balance sheet. However, our financial results continued to be significantly impacted by low crude oil prices. Average crude oil benchmark prices declined approximately 50 percent from 2014. The expectation of sustained low commodity prices resulted in asset impairments of $338 million, further decreasing our earnings.

During 2015, Cenovus remained focused on delivering value through preserving financial resilience, achieving sustainable cost reductions and exercising capital discipline. We captured savings of approximately $540 million, relative to our budget, by reducing our capital, operating, and general and administrative spending. Approximately 50 percent of these savings came from lower than budgeted operating costs and 40 percent from reduced capital expenditures, including supply chain management initiatives.

In 2015, we also:

- Issued 67.5 million common shares at $22.25 per share for net proceeds of $1.4 billion;
- Completed the sale of our royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion;
- Renegotiated our $3.0 billion committed credit facility, extending the maturity date to November 30, 2019 and added a new $1.0 billion tranche under the same facility with a maturity date of November 30, 2017;
- Reduced capital investment by 44 percent or $1.3 billion, compared with 2014;
- Realized gains of $656 million from crude oil and natural gas risk management activities;
- Reduced our workforce by 24 percent to align with our more moderate approach to oil sands expansions;
- Decreased our total crude oil operating costs by 20 percent or $228 million, compared with 2014;
- Increased proved bitumen reserves by 11 percent primarily due to approval of an area expansion at Christina Lake;
- Closed the purchase of a crude-by-rail terminal for $75 million, plus adjustments, to expand our portfolio of transportation options;
- Received regulatory approval for Christina Lake phase H, a 50,000 gross barrels per day phase; and
- Reduced our annual dividend from $1.0648 per share to $0.8524 per share.

OPERATING RESULTS

Our upstream assets continued to perform well in 2015. Total crude oil production averaged 206,947 barrels per day during the year.

Crude Oil Production Volumes

(barrels per day)	2015	Percent Change	2014	Percent Change	2013
Oil Sands					
Foster Creek	**65,345**	**10%**	59,172	11%	53,190
Christina Lake	**74,975**	**9%**	69,023	40%	49,310
	140,320	**9%**	128,195	25%	102,500
Conventional					
Heavy Oil	**34,888**	**(12)%**	39,546	(2)%	40,245
Light and Medium Oil	**30,486**	**(12)%**	34,531	(3)%	35,467
NGLs [1]	**1,253**	**3%**	1,221	15%	1,063
	66,627	**(12)%**	75,298	(2)%	76,775
Total Crude Oil Production	**206,947**	**2%**	203,493	14%	179,275

(1) NGLs include condensate volumes.

Foster Creek production increased in 2015 due to the ramp-up of production from phase F and production from additional wells, partially offset by the impact of a forest fire in the second quarter, which decreased full-year production by approximately 2,600 barrels per day. Fourth quarter production was lower compared with 2014. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which combined with the faster declines, contributed to lower fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

Production from Christina Lake increased compared with 2014 due to production from additional wells and improved performance of our facilities.

In 2015, our Conventional crude oil production decreased from 2014. An increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and mineral fee title lands business. Production also declined due to reduced capital investment. Divested assets contributed 2,555 barrels per day (2014 – 6,532 barrels per day) to annual production.

Natural Gas Production Volumes

(MMcf per day)	2015	2014	2013
Conventional	**422**	466	508
Oil Sands	**19**	22	21
	441	488	529

Our natural gas production declined 10 percent in 2015. Production decreased primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business, which produced 10 MMcf per day during the year (2014 – 20 MMcf per day).

Oil and Gas Reserves

Our proved bitumen reserves increased 11 percent to approximately 2.2 billion barrels and our proved plus probable bitumen reserves remained at approximately at 3.3 billion barrels. Additional information about our reserves and resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

Operating Netbacks

	Crude Oil [1] ($/bbl)			Natural Gas ($/Mcf)		
	2015	2014	2013	**2015**	2014	2013
Price [2]	**35.38**	71.35	67.01	**2.92**	4.37	3.20
Royalties	**1.75**	6.18	5.01	**0.07**	0.08	0.04
Transportation and Blending [2] [3]	**5.48**	2.98	3.12	**0.11**	0.12	0.11
Operating Expenses [4]	**11.98**	15.40	15.49	**1.20**	1.22	1.16
Production and Mineral Taxes	**0.22**	0.50	0.48	**0.01**	0.05	0.02
Netback Excluding Realized Risk Management	**15.95**	46.29	42.91	**1.53**	2.90	1.87
Realized Risk Management Gain (Loss)	**7.51**	0.50	1.09	**0.37**	0.04	0.32
Netback Including Realized Risk Management	**23.46**	46.79	44.00	**1.90**	2.94	2.19

(1) Includes NGLs.
(2) The crude oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate was $21.09 per barrel (2014 – $30.49 per barrel; 2013 – $28.33 per barrel).
(3) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013. See the Oil Sands and Conventional Reportable Segments sections of this MD&A for more details.
(4) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.

Our average crude oil netback in 2015, excluding realized risk management gains and losses, decreased significantly compared with 2014. Lower sales prices, consistent with the decline in benchmark prices, were partially offset by weakening of the Canadian dollar relative to the U.S. dollar and a decline in royalties and operating costs. The weakening of the Canadian dollar compared with 2014 had a positive impact on our crude oil price of approximately $4.81 per barrel.

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

Refining

In 2015, we successfully completed planned turnarounds at both of our Borger and Wood River refineries and received permit approval for the Wood River debottlenecking project.

	2015	**Percent Change**	2014	Percent Change	2013
Crude Oil Runs [1] (Mbbls/d)	**419**	**(1)%**	423	(4)%	442
Heavy Crude Oil [1]	**200**	**1%**	199	(10)%	222
Refined Product [1] (Mbbls/d)	**444**	**-**	445	(4)%	463
Crude Utilization [1] (percent)	**91**	**(1)%**	92	(5)%	97

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

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

	Q4 2015	**Percent Change**	Q4 2014	**2015**	2014	2013
Crude Oil Prices (US$/bbl)						
Brent						
Average	**44.71**	**(42)%**	76.98	**53.64**	99.51	108.76
End of Period	**37.28**	**(35)%**	57.33	**37.28**	57.33	110.80
WTI						
Average	**42.18**	**(42)%**	73.15	**48.80**	93.00	97.97
End of Period	**37.04**	**(30)%**	53.27	**37.04**	53.27	98.42
Average Differential Brent-WTI	**2.53**	**(34)%**	3.83	**4.84**	6.51	10.79
WCS [2]						
Average	**27.69**	**(53)%**	58.91	**35.28**	73.60	72.77
End of Period	**24.98**	**(34)%**	37.59	**24.98**	37.59	74.80
Average Differential WTI-WCS	**14.49**	**2%**	14.24	**13.52**	19.40	25.20
Condensate (C5 @ Edmonton) [3]						
Average	**41.67**	**(41)%**	70.57	**47.36**	92.95	101.69
Average Differential WTI-Condensate (Premium)/Discount	**0.51**	**(80)%**	2.58	**1.44**	0.05	(3.72)
Average Differential WCS-Condensate (Premium)/Discount	**(13.98)**	**20%**	(11.66)	**(12.08)**	(19.35)	(28.92)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	**55.24**	**(32)%**	81.26	**67.68**	107.40	116.35
Chicago Ultra-low Sulphur Diesel ("ULSD")	**59.23**	**(42)%**	101.48	**68.12**	117.55	126.31
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)						
Chicago	**14.47**	**(1)%**	14.60	**19.11**	17.61	21.77
Group 3	**13.82**	**4%**	13.28	**18.16**	16.27	20.80
Average Natural Gas Prices						
AECO (C$/Mcf)	**2.65**	**(34)%**	4.01	**2.77**	4.42	3.17
NYMEX (US$/Mcf)	**2.27**	**(43)%**	4.00	**2.66**	4.42	3.65
Basis Differential NYMEX-AECO (US$/Mcf)	**0.27**	**(39)%**	0.44	**0.49**	0.40	0.58
Foreign Exchange Rates (US$ per C$1)						
Average	**0.749**	**(15)%**	0.881	**0.782**	0.905	0.971

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

(2) The average Canadian dollar WCS benchmark price for 2015 was $45.12 per barrel (2014 – $81.33 per barrel; 2013 – $74.94 per barrel); fourth quarter average WCS benchmark price was $36.97 per barrel (2014 – $66.87 per barrel).

(3) The average Canadian dollar condensate benchmark price for 2015 was $60.56 per barrel (2014 – $102.71 per barrel; 2013 – $104.73 per barrel); fourth quarter average condensate benchmark price was $55.63 per barrel (2014 – $80.10 per barrel).

Crude Oil Benchmarks

The average Brent, WTI and WCS benchmark prices continued to be impacted by a global imbalance of supply and demand which began in the second half of 2014. This imbalance, created by weak global demand for oil and strong growth in North American crude oil supply, was further amplified by the sustained decision of the Organization of Petroleum Exporting Countries ("OPEC") to maintain its level of crude oil output and discontinue its role as the swing supplier of crude oil. Despite significantly lower crude oil prices and increased global demand in 2015, the imbalance has only slightly improved. Economic uncertainty in China, resilient U.S. production, continued strong production from Saudi Arabia and Iraq, as well as concerns regarding the return of Iranian production have contributed to sustained low crude oil prices.

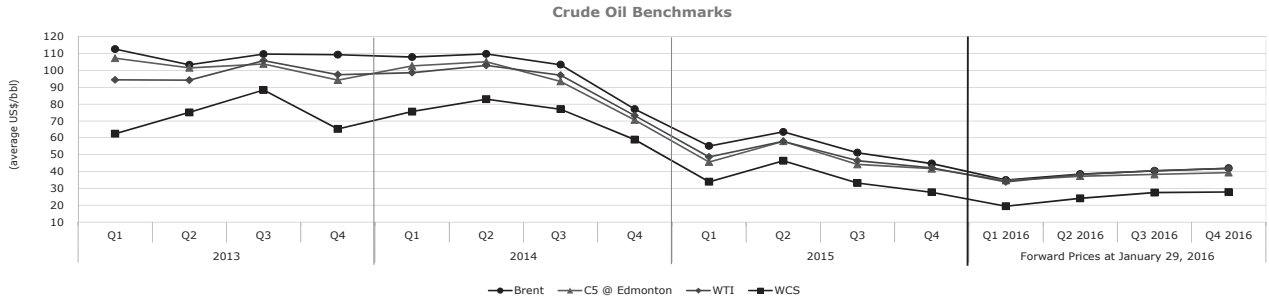
The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed compared with 2014. WTI benchmark prices strengthened relative to Brent as a result of high global crude oil inventory levels and continued strong demand in the U.S., leaving transportation costs as the primary driver of the Brent-WTI differential.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed in 2015. The narrower differential resulted primarily from increased demand for WCS due to new pipeline infrastructure to the U.S. Gulf Coast, growing rail capacity and the slow return of heavy crude oil supply forced offline due to forest fires in northeastern Alberta during the second quarter of 2015.

Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton.

The average WCS-Condensate differential narrowed in 2015 due to condensate supply growth as well as improved diluent transportation infrastructure for condensate imports into Alberta and heavy oil exports to market.

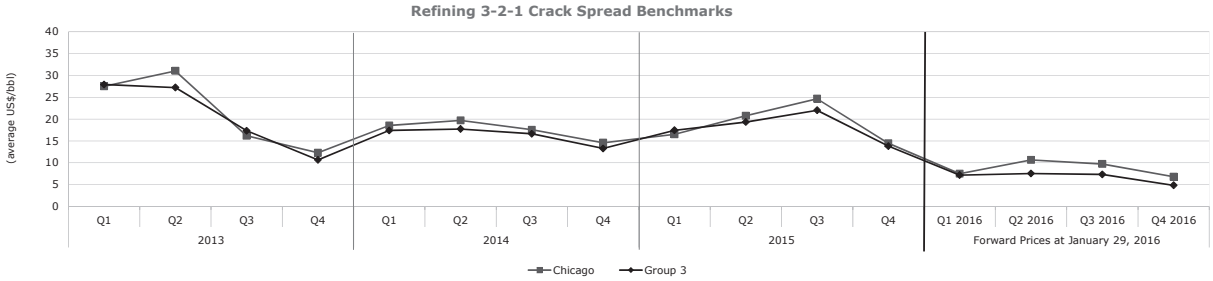


Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 crack spread. The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average Chicago 3-2-1 crack spreads increased in 2015 compared with 2014 driven by stronger product demand. Average Group 3 crack spreads increased as a major unplanned refinery outage in August 2015 caused product inventory drawdowns during the driving season.

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



Natural Gas Benchmarks

Average natural gas prices decreased in 2015 primarily due to increased supply from the U.S. and Canada.

Foreign Exchange Benchmarks

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

In 2015 compared with 2014, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices, strengthening of the U.S. economy, and Canadian political and economic uncertainty. The weakening of the Canadian dollar compared with 2014 had a positive impact of approximately $1,772 million on our revenues and also resulted in $1,064 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

Sustained low commodity prices in 2015 significantly impacted our financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	**2015**	**Percent Change**	2014	Percent Change	2013
Revenues	**13,064**	**(33)%**	19,642	5%	18,657
Operating Cash Flow [(1) (2)]	**2,439**	**(42)%**	4,179	(7)%	4,484
Cash Flow [(1)]	**1,691**	**(51)%**	3,479	(4)%	3,609
Per Share – Diluted	**2.07**	**(55)%**	4.59	(4)%	4.76
Operating Earnings (Loss) [(1)]	**(403)**	**(164)%**	633	(46)%	1,171
Per Share – Diluted	**(0.49)**	**(158)%**	0.84	(46)%	1.55
Net Earnings (Loss)	**618**	**(17)%**	744	12%	662
Per Share – Basic	**0.75**	**(23)%**	0.98	11%	0.88
Per Share – Diluted	**0.75**	**(23)%**	0.98	13%	0.87
Total Assets	**25,791**	**4%**	24,695	(2)%	25,224
Total Long-Term Financial Liabilities [(3)]	**6,552**	**19%**	5,484	(10)%	6,113
Capital Investment [(4)]	**1,714**	**(44)%**	3,051	(6)%	3,262
Dividends					
Cash Dividends	**528**	**(34)%**	805	10%	732
In Shares from Treasury	**182**	**-**	-	-	-
Per Share	**0.8524**	**(20)%**	1.0648	10%	0.968

(1) Non-GAAP measure defined in this MD&A.
(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs. There were no changes to Cash Flow, Operating Earnings or Net Earnings.
(3) Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(4) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

Revenues

($ millions)	**2015 vs. 2014**	2014 vs. 2013
Revenues, Comparative Year	**19,642**	18,657
Increase (Decrease) due to:		
Oil Sands	**(1,799)**	1,020
Conventional	**(1,401)**	220
Refining and Marketing	**(3,853)**	(48)
Corporate and Eliminations	**475**	(207)
Revenues, End of Year	**13,064**	19,642

Combined Oil Sands and Conventional revenues declined 41 percent in 2015 due to lower crude oil blend and natural gas sales prices, partially offset by higher crude oil sales volumes, weakening of the Canadian dollar relative to the U.S. dollar and lower royalties. The sale of our royalty interest and mineral fee title lands business also reduced revenues.

Revenues from our Refining and Marketing segment decreased 30 percent from 2014. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices. The decrease in our reported revenues was partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in 2015 decreased 36 percent from 2014, primarily due to a decline in sales prices, partially offset by an increase in purchased crude oil volumes.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

Overall, revenues increased in 2014 compared with 2013 primarily due to higher blended crude oil sales volumes and higher average sales prices for blended crude oil and natural gas, partially offset by an increase in royalties.

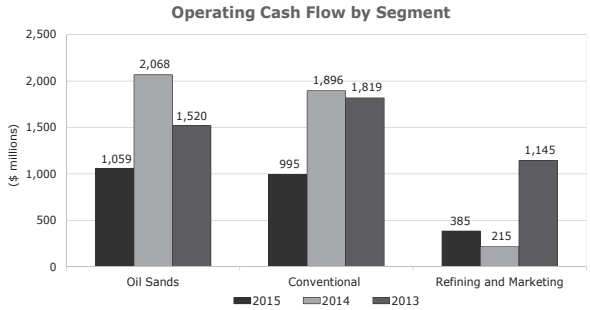
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

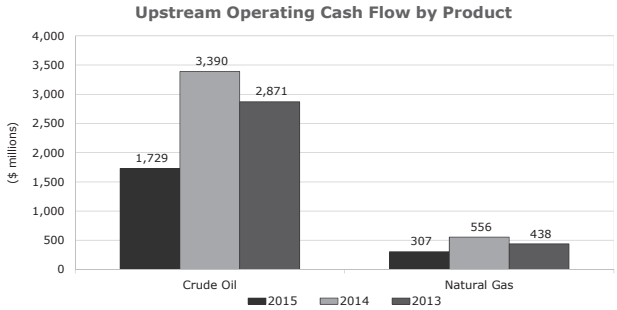
Operating Cash Flow

Operating Cash Flow is a non-GAAP measure used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

($ millions)	**2015**	2014	2013
Revenues	**13,401**	20,454	19,262
(Add) Deduct:			
Purchased Product	**7,709**	11,767	11,004
Transportation and Blending	**2,045**	2,477	2,074
Operating Expenses [(1)]	**1,846**	2,051	1,787
Production and Mineral Taxes	**18**	46	35
Realized (Gain) Loss on Risk Management Activities	**(656)**	(66)	(122)
Operating Cash Flow	**2,439**	4,179	4,484

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





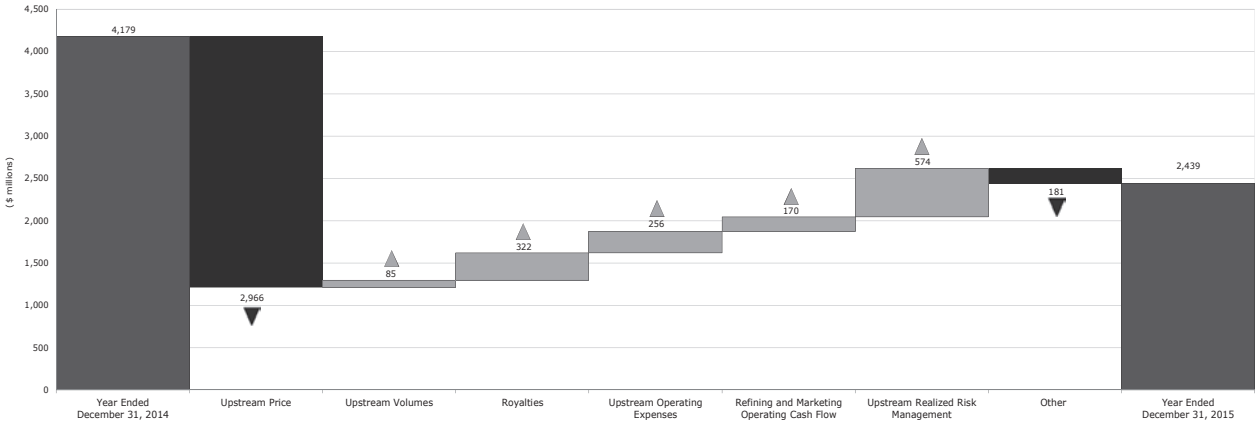
Operating Cash Flow declined 42 percent in 2015 primarily due to:

- A 50 percent decrease in our average crude oil sales price and a 33 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices; and
- A 10 percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- Realized risk management gains of $613 million, excluding Refining and Marketing, compared with $39 million in 2014;
- Lower royalties primarily due to a decrease in crude oil sales prices;
- A decrease of $3.42 per barrel in crude oil operating expenses primarily due to a decline in workover activities, a reduction in fuel costs due to lower natural gas prices, and lower repairs and maintenance costs;
- Higher Operating Cash Flow from Refining and Marketing as a result of improved margins on the sale of secondary products, such as coke and asphalt, and weakening of the Canadian dollar relative to the U.S. dollar, partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and higher operating costs; and
- An inventory write-down of $66 million compared with an inventory write-down of $131 million in 2014.

Operating Cash Flow Variance



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

Cash Flow

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

($ millions)	**2015**	2014	2013
Cash From Operating Activities	**1,474**	3,526	3,539
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(107)**	(135)	(120)
Net Change in Non-Cash Working Capital	**(110)**	182	50
Cash Flow	**1,691**	3,479	3,609

In 2015, Cash Flow decreased due to a combination of lower Operating Cash Flow, as discussed above, and higher current income tax. Current income tax rose due to the timing of recognition of partnership income for tax purposes.

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure 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.

($ millions)	**2015**	2014	2013
Earnings, Before Income Tax	**537**	1,195	1,094
Add (Deduct):			
Unrealized Risk Management (Gain) Loss [1]	**195**	(596)	415
Non-operating Unrealized Foreign Exchange (Gain) Loss [2]	**1,064**	458	52
Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable	**-**	-	146
(Gain) Loss on Divestiture of Assets	**(2,392)**	(156)	1
Operating Earnings (Loss), Before Income Tax	**(596)**	901	1,708
Income Tax Expense (Recovery)	**(193)**	268	537
Operating Earnings (Loss)	**(403)**	633	1,171

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

Operating Earnings decreased compared with 2014 primarily due to lower Cash Flow, and higher depreciation, depletion and amortization ("DD&A") and exploration expense due to asset impairments. These items were partially offset by a recovery of deferred income tax compared with an expense in 2014 and a goodwill impairment of $497 million recorded in 2014.

Net Earnings

($ millions)	**2015 vs. 2014**	2014 vs. 2013
Net Earnings, Comparative Year	**744**	662
Increase (Decrease) due to:		
Operating Cash Flow [1] [2]	**(1,740)**	(305)
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(791)**	1,011
Unrealized Foreign Exchange Gain (Loss)	**(686)**	(371)
Gain (Loss) on Divestiture of Assets	**2,236**	157
Expenses [2] [3]	**46**	191
Depreciation, Depletion and Amortization	**(168)**	(113)
Goodwill Impairment	**497**	(497)
Exploration Expense	**(52)**	28
Income Tax Expense	**532**	(19)
Net Earnings, End of Year	**618**	744

(1) Non-GAAP measure defined in this MD&A.
(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.
(3) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

In 2015, Net Earnings declined as an after-tax gain of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business, and a deferred tax recovery related to non-operating items compared with an expense in 2014, were more than offset by:

- A decline in Operating Earnings, as discussed above;
- Unrealized risk management losses, after-tax, of $141 million (2014 – unrealized gains of $444 million); and
- Non-operating unrealized foreign exchange losses, after-tax, of $1,064 million (2014 – $458 million).

Net Earnings increased in 2014 compared with 2013 primarily due to unrealized risk management gains compared with losses in 2013, a gain on the sale of non-core assets and no realized foreign exchange loss in 2014 related to the Partnership Contribution Receivable, partially offset by a decline in operating earnings and higher non-operating unrealized foreign exchange losses.

Net Capital Investment

($ millions)	**2015**	2014	2013
Oil Sands	**1,185**	1,986	1,885
Conventional	**244**	840	1,189
Refining and Marketing	**248**	163	107
Corporate and Eliminations	**37**	62	81
Capital Investment	**1,714**	3,051	3,262
Acquisitions	**87**	18	32
Divestitures	**(3,344)**	(277)	(283)
Net Capital Investment [1]	**(1,543)**	2,792	3,011

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

Capital investment in 2015 declined 44 percent as we reduced our capital investment in light of the low commodity price environment.

In 2015, Oil Sands capital investment focused on sustaining capital related to existing production, the phase G expansion at Foster Creek, and Christina Lake optimization project and phase F expansion. We drilled 164 gross stratigraphic test wells at Foster Creek and Christina Lake to determine pad placement for sustaining wells and near-term expansion phases.

Conventional capital investment focused on maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn and drilling activity in the second half of the year at our tight oil projects in southeast Alberta.

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

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

Acquisitions and Divestitures

In 2015, we completed the sale of our royalty interest and mineral fee title lands business for cash proceeds of approximately $3.3 billion, recording an after-tax gain of approximately $1.9 billion. The sale included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. A royalty on Cenovus's working interest production on these fee lands and a Gross Overriding Royalty ("GORR") on production from our Pelican Lake and Weyburn assets were also included.

In 2015, we purchased a crude-by-rail terminal for $75 million, plus adjustments, to expand our portfolio of transportation options.

Divestitures in 2014 primarily included the sale of certain of our Bakken assets in southeastern Saskatchewan and the sale of certain of our Wainwright assets in Alberta for net proceeds of $269 million, resulting in a gain of $153 million. In 2013, divestitures included the sale of our Lower Shaunavon asset for net proceeds of $241 million, resulting in a loss of $2 million.

We had no material acquisitions in 2014 or 2013.

Capital Investment Decisions

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

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

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria within the context of achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which position us to be financially resilient in times of lower cash flow. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

($ millions)	**2015**	2014	2013
Cash Flow [1]	**1,691**	3,479	3,609
Capital Investment (Committed and Growth)	**1,714**	3,051	3,262
Free Cash Flow [2]	**(23)**	428	347
Cash Dividends	**528**	805	732
	(551)	(377)	(385)

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

We expect our capital investment for 2016 to be funded from internally generated cash flow and our cash balance on hand.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

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 Cenovus's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

Conventional, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, 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.

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

Revenues by Reportable Segment

($ millions)	**2015**	2014	2013
Oil Sands	**3,001**	4,800	3,780
Conventional	**1,595**	2,996	2,776
Refining and Marketing	**8,805**	12,658	12,706
Corporate and Eliminations	**(337)**	(812)	(605)
	13,064	19,642	18,657

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of development, including our 100 percent-owned projects at Telephone Lake and Grand Rapids. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant developments in our Oil Sands segment in 2015 compared with 2014 include:

- Production at Foster Creek increasing 10 percent, to an average of 65,345 barrels per day, primarily as a result of the ramp-up of phase F, partially offset by the impact of a forest fire in the second quarter. Fourth quarter production was lower compared with 2014. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which combined with the faster declines, contributed to lower fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production;
- Christina Lake production increasing nine percent, to an average of 74,975 barrels per day primarily due to production from additional wells, and improved performance of our facilities;
- Completion of the optimization project at Christina Lake, which is expected to add 22,000 barrels per day of gross production capacity. Incremental production from the project is anticipated in 2016;
- Reducing our crude oil operating costs by $104 million or $3.37 per barrel; and
- Receiving regulatory approval for Christina Lake phase H, a 50,000 gross barrels per day phase.

Oil Sands – Crude Oil

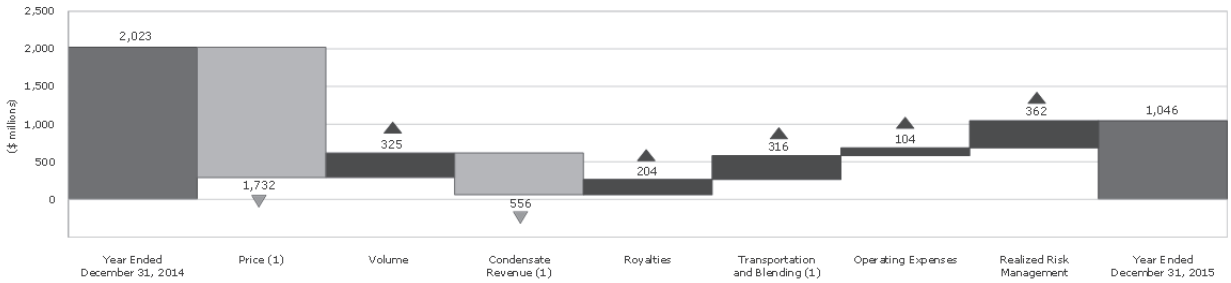
Financial and Per-unit Results

($ millions, unless otherwise noted)	2015	$ per-unit [1]	2014	$ per-unit [1]	2013	$ per-unit [1]
Gross Sales	**3,000**	60	4,963	109	3,850	103
Less: Royalties	**29**	1	233	5	131	4
Revenues	**2,971**	59	4,730	104	3,719	99
Expenses						
Transportation and Blending	**1,814**	36	2,130	47	1,748	47
Operating [2]	**511**	10	615	14	527	14
(Gain) Loss on Risk Management	**(400)**	(8)	(38)	(1)	(33)	(1)
Operating Cash Flow	**1,046**	21	2,023	44	1,477	39
Capital Investment	**1,184**		1,980		1,880	
Operating Cash Flow Net of Related Capital Investment	**(138)**		43		(403)	

(1) Per-unit amounts are calculated on an unblended crude oil basis.
(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments in 2015 and 2013. Proceeds from our common share issuance and the sale of our royalty interest and mineral fee title lands business also contributed to funding our capital investment in 2015.

Operating Cash Flow Variance



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

Revenues

Pricing

In 2015, our average crude oil sales price was $30.88 per barrel, a 53 percent decrease from 2014 as the prices we received were adversely impacted by the worldwide low commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market which generally secure a higher sales price. The WCS-CDB differential narrowed by 40 percent to a discount of US$2.37 per barrel (2014 – a discount of US$3.94 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In 2015, 86 percent of our Christina Lake production was sold as CDB (2014 – 88 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	2015	Percent Change	2014	Percent Change	2013
Foster Creek	**65,345**	**10%**	59,172	11%	53,190
Christina Lake	**74,975**	**9%**	69,023	40%	49,310
	140,320	**9%**	128,195	25%	102,500

Foster Creek production increased in 2015 primarily due to the ramp-up of phase F and production from additional wells. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately 18 months from start-up, which occurred in the third quarter of 2014. Production increases were partially offset when production at Foster Creek was shut down for 11 full days as a safety precaution due to a nearby forest fire. The forest fire decreased production by approximately 2,600 barrels per day. Fourth quarter production was lower compared with 2014. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines

from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which combined with the faster declines, contributed to lower fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

Production from Christina Lake increased in 2015 due to production from additional wells, phase E reaching nameplate production capacity in the second quarter of 2014, and improved performance of our facilities.

Condensate

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

Royalties

Royalty calculations for our oil sands projects are based on government prescribed pre- and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price. Royalty calculations differ between properties.

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

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Effective Royalty Rates

(percent)	**2015**	2014	2013
Foster Creek	**1.9**	8.8	5.8
Christina Lake	**2.8**	7.5	6.8

Royalties decreased $204 million, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. At Foster Creek, the royalty calculation was based on gross revenues as compared with a calculation based on net profits for 2014. In the first quarter of 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation and recorded an associated credit, decreasing the overall royalty rate. Excluding the credit, the effective royalty rate for Foster Creek would have been 3.1 percent in 2015. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $316 million or 15 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes, consistent with the rise in production. In 2015, we recorded a $44 million (2014 – $6 million) write-down of our blended crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices. Our condensate costs were higher than the average benchmark price in 2015 primarily due to the utilization of higher-priced inventory and the transportation costs associated with moving the condensate to our oil sands projects.

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

We incurred higher transportation charges on the Trans Mountain pipeline system, with our long-term commitment for firm service. Transportation costs also increased as lower volumes moved by rail were more than offset by new lease costs for railcars, and higher loading fees and storage costs. In 2015, we transported an average of 7,057 gross barrels per day of crude oil by rail, consisting of 43 unit train shipments (2014 – 7,325 gross barrels per day, 47 unit train shipments).

Operating

Primary drivers of our operating expenses for 2015 were workforce, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses decreased $104 million or $3.37 per barrel, primarily as a result of lower

natural gas prices that reduced fuel costs, higher production, a decline in workover activities and efforts from our supply chain management.

Per-unit Operating Expenses

($/bbl)	2015	Percent Change	2014	Percent Change	2013
Foster Creek					
Fuel	**2.80**	**(37)%**	4.46	55%	2.88
Non-fuel [1]	**9.80**	**(18)%**	11.89	(7)%	12.74
Total	**12.60**	**(23)%**	16.35	5%	15.62
Christina Lake					
Fuel	**2.20**	**(40)%**	3.65	20%	3.03
Non-fuel [1]	**5.81**	**(22)%**	7.44	(20)%	9.34
Total	**8.01**	**(28)%**	11.09	(10)%	12.37
Total	**10.13**	**(25)%**	13.50	(4)%	14.07

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

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

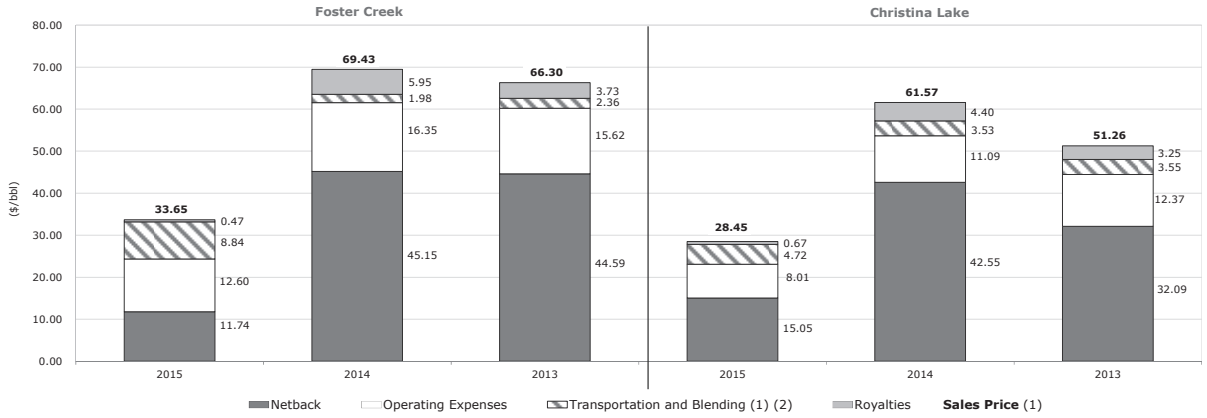
- Higher production volumes;
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes; and
- Lower electricity costs.

Foster Creek non-fuel operating expenses included approximately $2.6 million or $0.11 per barrel of incremental costs associated with the shut-down due to a nearby forest fire that occurred in the second quarter of 2015.

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

- Increased production;
- Lower workover costs related to fewer pump changes; and
- A decrease in repairs and maintenance costs due to a focus on critical operational activities and no turnaround costs in 2015.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in 2015 was $27.44 per barrel (2014 – $42.01 per barrel; 2013 – $42.41 per barrel) for Foster Creek, and $29.50 per barrel (2014 – $45.45 per barrel; 2013 – $45.25 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

(2) The netbacks do not reflect non-cash write-downs of product inventory in 2015 and 2014. There was no product inventory write-down recorded in 2013.

Risk Management

Risk management activities in 2015 resulted in realized gains of $400 million (2014 – $38 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for 2015, net of internal usage, was 19 MMcf per day (2014 – 22 MMcf per day). Operating Cash Flow was $10 million in 2015 (2014 – $46 million) primarily due to the decline in natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	**2015**	2014	2013
Foster Creek	**403**	796	797
Christina Lake	**647**	794	688
	1,050	1,590	1,485
Narrows Lake	**47**	175	152
Telephone Lake	**24**	112	93
Grand Rapids	**38**	63	39
Other [1]	**26**	46	116
Capital Investment [2]	**1,185**	1,986	1,885

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

Existing Projects

Capital investment at Foster Creek in 2015 focused on sustaining capital related to existing production, expansion phase G and the drilling of stratigraphic test wells. In 2015, capital investment declined mainly due to the start-up of phase F in the third quarter of 2014.

In 2015, Christina Lake capital investment focused on sustaining capital related to existing production, expansion phases F and G, and the optimization project. The optimization project has been completed and is expected to add 22,000 barrels per day of gross production capacity. Incremental production from the optimization project is anticipated in 2016. Capital investment in 2015 decreased from 2014 due to lower spending on phase F facilities, partially offset by increased investment in sustaining activities.

Capital investment at Narrows Lake in 2015 was mainly on detailed engineering and construction wind-down. Capital investment declined in 2015 compared with 2014 due to the suspension of construction at Narrows Lake.

Emerging Projects

In 2015, Telephone Lake capital investment focused primarily on completing front-end engineering work on the central processing facility and preliminary infrastructure development. Capital spending decreased in 2015 as we did not drill any stratigraphic test wells during the year (2014 – 45 stratigraphic test wells).

Capital investment at Grand Rapids in 2015 focused on continued operation of the SAGD pilot project. A third well pair was drilled, completed and commenced steam circulation. Capital investment decreased in 2015 compared with 2014 as there were no stratigraphic test wells drilled in 2015 (2014 – 10 stratigraphic test wells) and all work related to the dismantling and removal of an existing SAGD facility purchased in 2014 was completed.

Drilling Activity [1]

	Gross Stratigraphic Test Wells [2]			**Gross Production Wells [3]**		
	2015	2014	2013	**2015**	2014	2013
Foster Creek	**124**	165	112	**28**	63	56
Christina Lake	**40**	57	74	**67**	67	35
	164	222	186	**95**	130	91
Narrows Lake	**-**	22	26	**-**	-	-
Telephone Lake	**-**	45	28	**-**	-	-
Grand Rapids	**-**	10	3	**1**	-	-
Other	**-**	21	96	**-**	-	-
	164	320	339	**96**	130	91

(1) In addition to the drilling activity included within the table, we drilled eight gross service wells in 2015 (2014 – three gross service wells; 2013 – 27 gross service wells).
(2) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In 2015, we drilled seven wells (2014 – 14 wells; 2013 – 24 wells) and commissioned our second SkyStrat™ drilling rig.
(3) SAGD well pairs are counted as a single producing well.

Stratigraphic test wells were drilled at Foster Creek and Christina Lake to help identify well pad locations for sustaining wells and near-term expansion phases.

Future Capital Investment

Due to our expectation that low commodity prices will persist for an extended period, we have adopted a more moderate and staged approach to future oil sands expansions. Expanding existing projects and developing emerging projects will depend upon commodity prices, achieving further cost reductions as well as additional fiscal and regulatory certainty.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2016 is forecast to be between $325 million and $350 million. We plan to continue focusing on sustaining capital related to existing production as well as completing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day and first production is anticipated in the third quarter of 2016. Spending related to construction work on phase H was deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase H has an initial design capacity of 30,000 gross barrels per day. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrels per day phase.

Christina Lake is producing from phases A through E. Capital investment for 2016 is forecast to be between $350 million and $375 million, focused on sustaining capital related to existing production and expansion phase F. We anticipate adding gross production capacity of 50,000 barrels per day from phase F in the third quarter of 2016. Construction work on phase G was deferred earlier in 2015 in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase G has an initial design capacity of 50,000 gross barrels per day. We received regulatory approval in December 2015 for the phase H expansion, a 50,000 gross barrels per day phase.

Capital investment at Narrows Lake in 2016 is forecast to be between $10 million and $20 million, focusing on completing phase A detailed engineering.

Emerging Projects

Capital investment for our new resource plays is forecast to be between $45 million and $55 million in 2016. As of February 2016, further activity in respect of the SAGD pilot at Grand Rapids has been deferred in response to the current low commodity price environment.

DD&A and Exploration Expense

DD&A

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

In 2015, Oil Sands DD&A increased $72 million primarily due to higher sales volumes and the impairment of a sulphur recovery facility for $16 million. The average depletion rate was approximately $11.65 per barrel compared with $10.85 per barrel in 2014 as the impact of higher PP&E and future development expenditures were only partially offset by proved reserves additions. Future development costs, which compose approximately 60 percent of the depletable base, increased due to the inclusion of Foster Creek phase J.

Exploration Expense

In 2015, $67 million of previously capitalized E&E costs, related to exploration assets within the Northern Alberta cash-generating unit ("CGU"), were deemed not to be technically feasible and commercially viable and were recorded as exploration expense. In 2014, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense.

CONVENTIONAL

Our Conventional operations include dependable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a CO_2 enhanced oil recovery project in Weyburn, our heavy oil asset at Pelican Lake that uses polymer flood technology and emerging tight oil assets in Alberta. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment while our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

On July 29, 2015, we completed the sale of our royalty interest and mineral fee title lands business, which included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. A royalty on our working interest production from these fee lands and a GORR on production from our Pelican Lake and Weyburn assets were also included in the sale. We received cash proceeds of approximately $3.3 billion and recorded an after-tax gain of approximately $1.9 billion. Associated third-party royalty interest volumes prior to the divestiture were approximately 6,580 barrels of oil equivalent per day.

Additional developments in our Conventional segment in 2015 compared with 2014 include:

- Crude oil production averaging 66,627 barrels per day, decreasing 12 percent, as an increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and mineral fee title lands business. Production also declined due to reduced capital investment;
- Reducing our crude oil operating costs by $124 million or $2.77 per barrel;
- Generating Operating Cash Flow net of capital investment of $751 million, a decrease of 29 percent;
- Recording an impairment of $184 million associated with our Northern Alberta CGU due to lower crude oil prices and a slowing down of the development plan; and
- Recording an exploration expense of $71 million related to previously capitalized exploration assets deemed not to be technically feasible and commercially viable.

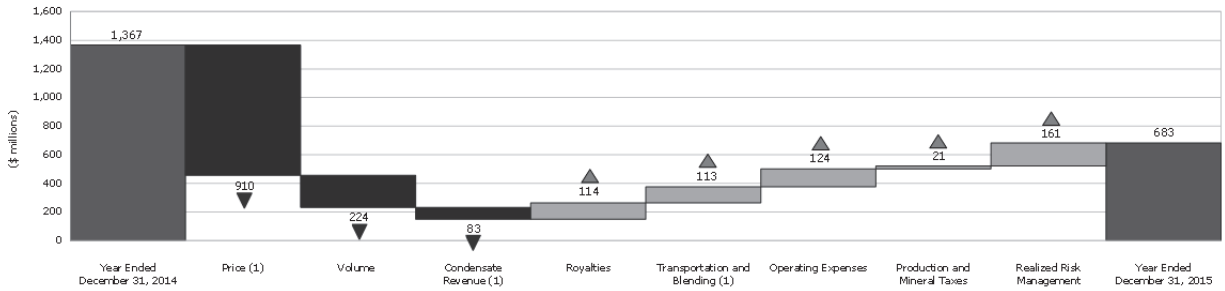
Conventional – Crude Oil

Financial and Per-unit Results

	2015		2014		2013	
($ millions, unless otherwise noted)		$ per-unit [1]		$ per-unit [1]		$ per-unit [1]
Gross Sales	**1,239**	51	2,456	90	2,373	85
Less: Royalties	**103**	4	217	8	196	7
Revenues	**1,136**	47	2,239	82	2,177	78
Expenses						
Transportation and Blending	**213**	9	326	12	305	11
Operating [2]	**381**	15	505	19	489	18
Production and Mineral Taxes	**16**	1	37	1	32	1
(Gain) Loss on Risk Management	**(157)**	(6)	4	-	(43)	(2)
Operating Cash Flow	**683**	28	1,367	50	1,394	50
Capital Investment	**231**		812		1,167	
Operating Cash Flow Net of Related Capital Investment	**452**		555		227	

(1) Per-unit amounts are calculated on an unblended crude oil basis.
(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs.

Operating Cash Flow Variance



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

Revenues

Pricing

Our average crude oil sales price was $44.63 per barrel in 2015, 45 percent lower than in 2014, consistent with the decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	**2015**	**Percent Change**	2014	Percent Change	2013
Heavy Oil	**34,888**	**(12)%**	39,546	(2)%	40,245
Light and Medium Oil	**30,486**	**(12)%**	34,531	(3)%	35,467
NGLs	**1,253**	**3%**	1,221	15%	1,063
	66,627	**(12)%**	75,298	(2)%	76,775

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and

mineral fee title lands business. Production also declined due to reduced capital investment. Divested assets contributed 2,555 barrels per day (2014 – 6,532 barrels per day) to annual production.

Condensate

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

Royalties

Royalties decreased $114 million primarily due to lower realized sales prices, partially offset by additional royalty burdens at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business. For 2015, the effective crude oil royalty rate for our Conventional properties was 9.9 percent (2014 – 10.1 percent).

Crown royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. The Pelican Lake royalty calculation was based on net profits in 2015 as compared with a calculation based on gross revenues in 2014.

In 2015, production and mineral taxes decreased, consistent with the decline in crude oil prices and due to the sale of our royalty interest and mineral fee title lands business.

Expenses

Transportation and Blending

Transportation and blending costs decreased $113 million. Blending costs declined primarily due to lower condensate prices. In 2015, we recorded a $7 million (2014 – $12 million) write-down of our crude oil and condensate inventory to net realizable value as a result of the decline in crude oil prices.

Transportation charges were lower largely due to a decline in sales volumes and a reduction in volumes moved by rail. We transported an average of 597 barrels per day of crude oil by rail (2014 – 2,706 barrels per day).

Operating

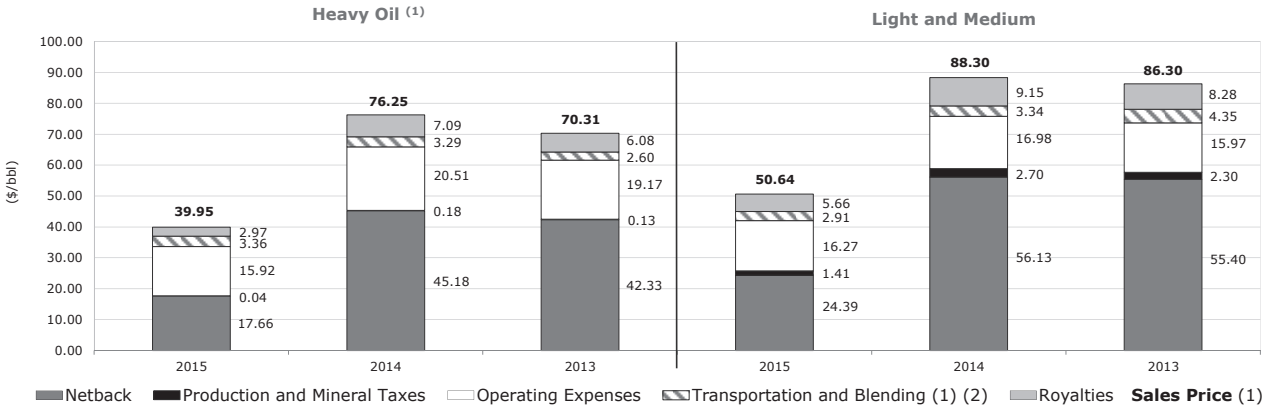
Primary drivers of our operating expenses for 2015 were workforce costs, workover activities, electricity and chemical consumption. Operating expenses declined $124 million or $2.77 per barrel.

The per-unit decline was primarily due to:

- A decline in workover costs and lower repairs and maintenance as a result of focusing on critical activities and achieving operational efficiencies;
- Lower trucking expenses as we added pipeline infrastructure;
- Lower chemical costs associated with reduced polymer consumption; and
- Lower electricity costs as a result of a decrease in consumption due in part to the disposition of non-core assets, and a decline in price.

These decreases were partially offset by lower production.

Operating Netbacks



(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $10.94 per barrel (2014 – $15.71 per barrel; 2013 – $14.60 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

(2) *The netbacks do not reflect non-cash write-downs of product inventory in 2015 and 2014. There was no product inventory write-down recorded in 2013.*

Risk Management

Risk management activities for 2015 resulted in realized gains of $157 million (2014 – realized losses of $4 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	**2015**	2014	2013
Gross Sales	**450**	744	594
Less: Royalties	**11**	12	8
Revenues	**439**	732	586
Expenses			
Transportation and Blending	**17**	20	20
Operating [1]	**175**	198	208
Production and Mineral Taxes	**2**	9	3
(Gain) Loss on Risk Management	**(52)**	(5)	(61)
Operating Cash Flow	**297**	510	416
Capital Investment	**13**	28	22
Operating Cash Flow Net of Related Capital Investment	**284**	482	394

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

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

Revenues

Pricing

In 2015, our average natural gas sales price decreased 33 percent to $2.93 per Mcf, consistent with the decline in the AECO benchmark price.

Production

Production decreased nine percent to 422 MMcf per day in 2015 (2014 – eight percent to 466 MMcf per day) due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 10 MMcf per day in 2015 (2014 – 20 MMcf per day).

Royalties

Royalties decreased slightly compared with 2014. Reduced royalties as a result of lower prices and production declines were offset by additional royalty burdens due to the sale of our royalty interest and mineral fee title lands business. The average royalty rate in 2015 was 2.7 percent (2014 – 1.6 percent).

Expenses

Transportation

In 2015, transportation costs decreased as a result of lower production volumes, partially offset by higher pipeline tariffs.

Operating

Primary drivers of our operating expenses were property taxes and lease costs, and workforce. In 2015, operating expenses decreased by $23 million primarily due to lower workforce costs, and repairs and maintenance, partially offset by lower production volumes.

Risk Management

Risk management activities resulted in realized gains of $52 million in 2015 (2014 – $5 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment

($ millions)	**2015**	2014	2013
Heavy Oil	**63**	338	598
Light and Medium Oil	**168**	474	569
Natural Gas	**13**	28	22
Capital Investment [1]	**244**	840	1,189

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

Capital investment declined in 2015 primarily due to spending reductions on crude oil activities in response to the low commodity price environment. Capital investment in 2015 was primarily related to maintenance capital, spending for our CO_2 enhanced oil recovery project at Weyburn and drilling activities at our tight oil projects in southeast Alberta.

Drilling Activity

(net wells, unless otherwise stated)	**2015**	2014	2013
Crude Oil	**32**	126	212
Recompletions	**724**	803	751
Gross Stratigraphic Test Wells	**13**	30	54
Other [(1)]	**3**	40	77

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

Drilling activity declined in 2015, reflecting the decision to suspend the majority of our 2015 drilling program in southern Alberta and Saskatchewan as a result of the low commodity price environment. In the second half of the year, modest drilling activities resumed at our tight oil projects in southeast Alberta and at our CO_2 enhanced oil recovery project at Weyburn.

Future Capital Investment

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

Our 2016 crude oil capital investment forecast is between $125 million and $150 million with spending plans mainly focused on maintaining and optimizing current production volumes.

DD&A, Goodwill Impairment and Exploration Expense

DD&A

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

Conventional DD&A increased $66 million in 2015 as a decline in sales volumes was more than offset by impairment losses and higher DD&A rates. The average depletion rate increased approximately five percent in 2015 as the impact of lower proved reserves due to the slowdown of our development plans was partially offset by lower PP&E. Future development costs, which compose approximately 30 percent of the depletable base, were consistent with 2014.

In 2015, we recorded an impairment loss of $184 million associated with our Northern Alberta CGU due to lower crude oil prices and a slowing down of our development plan. In 2014, an impairment loss of $52 million was recorded on equipment and in 2013, we recorded a $57 million impairment loss related to our Lower Shaunavon asset sold in July 2013.

Goodwill Impairment

In 2014, we recorded $497 million of goodwill impairment associated with our Pelican Lake property. There was no goodwill impairment in 2015 or 2013.

Exploration Expense

In 2015, $71 million (2014 – $82 million) of previously capitalized E&E costs related to exploration assets within the Northern Alberta and Saskatchewan CGUs that were deemed not to be technically feasible and commercially viable and were recorded as exploration expense.

In 2013, $50 million of exploration expense and $64 million of pre-exploration expense was recorded.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to our refineries.

Significant developments in our Refining and Marketing segment in 2015 compared with 2014 include:

- Closing the purchase of a crude-by-rail terminal for $75 million, plus adjustments. We commenced operating the terminal in August 2015 and loaded 34 unit trains, including 20 unit trains for third parties;
- Operating Cash Flow increasing 79 percent to $385 million primarily due to improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar and an increase in average market crack spreads, partially offset by higher heavy crude oil feedstock costs relative to the WTI benchmark price and higher operating costs;
- Receiving permit approval for the Wood River debottlenecking project;
- Successfully completing planned turnarounds at both of our Borger and Wood River refineries; and
- Exporting crude oil from the U.S. Gulf Coast to broaden market access for our crude oil production.

Refinery Operations [1]

	2015	2014	2013
Crude Oil Capacity [2] (Mbbls/d)	**460**	460	457
Crude Oil Runs (Mbbls/d)	**419**	423	442
Heavy Crude Oil	**200**	199	222
Light/Medium	**219**	224	220
Refined Products (Mbbls/d)	**444**	445	463
Gasoline	**228**	231	232
Distillate	**137**	137	144
Other	**79**	77	87
Crude Utilization (percent)	**91**	92	97

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

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

In 2015, crude oil runs and refined product output were slightly lower compared with 2014. The unplanned outages and planned turnarounds at both of our refineries in 2015 had a similar impact on crude oil runs and refined product output as the outage and turnarounds in 2014.

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process a wide slate of crude oils, a feedstock cost advantage is created by processing less expensive crude oil. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit. The volume of heavy crude oil processed in 2015 increased slightly from 2014.

Financial Results

($ millions)	**2015**	2014	2013
Revenues	**8,805**	12,658	12,706
Purchased Product	**7,709**	11,767	11,004
Gross Margin	**1,096**	891	1,702
Expenses			
Operating [1]	**754**	703	538
(Gain) Loss on Risk Management	**(43)**	(27)	19
Operating Cash Flow	**385**	215	1,145
Capital Investment	**248**	163	107
Operating Cash Flow Net of Related Capital Investment	**137**	52	1,038

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

Gross Margin

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

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

- Improved margins on the sale of our secondary products, such as coke and asphalt, due to lower overall feedstock costs consistent with the decline in WTI;
- Weakening of the Canadian dollar relative to the U.S. dollar; and
- An inventory write-down of $15 million related to our refined product inventory, compared with a write-down of $113 million in 2014.

The increase in gross margin was partially offset by higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential.

The weakening of the Canadian dollar relative to the U.S. dollar in 2015, compared with 2014, had a positive impact of approximately $143 million on our refining gross margin.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers ("RINs"). In 2015, the cost of our RINs was $200 million (2014 – $123 million). The increase is consistent with the rise in the ethanol RINs benchmark price.

Revenues and purchased product from third-party crude oil and natural gas sales undertaken by the marketing group in 2015 decreased 36 percent and 38 percent, respectively, from 2014, primarily due to a decline in sales prices, partially offset by an increase in purchased crude oil volumes.

Operating Expense

Primary drivers of operating expenses in 2015 were maintenance, labour, utilities and supplies. Reported operating expenses increased compared with 2014 primarily due to weakening of the Canadian dollar relative to the U.S. dollar, partially offset by a decline in utility costs resulting from lower natural gas prices.

Refining and Marketing – Capital Investment

($ millions)	**2015**	2014	2013
Wood River Refinery	**162**	101	64
Borger Refinery	**78**	61	42
Marketing	**8**	1	1
	248	163	107

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

In 2016, we expect to invest between $240 million and $290 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from 3 to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $35 million in 2015, primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, and the unrealized mark-to-market gains and losses on the long-term power purchase contract and interest rate swaps. In 2015, our risk management activities resulted in $195 million of unrealized losses (2014 – $596 million of unrealized gains). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

($ millions)	**2015**	2014	2013
General and Administrative [(1)]	**335**	379	365
Finance Costs	**482**	445	529
Interest Income	**(28)**	(33)	(96)
Foreign Exchange (Gain) Loss, Net	**1,036**	411	208
Research Costs	**27**	15	24
(Gain) Loss on Divestiture of Assets	**(2,392)**	(156)	1
Other (Income) Loss, Net	**2**	(4)	2
	(538)	1,057	1,033

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

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2015 were workforce, office rent and information technology costs. General and administrative expenses decreased by $87 million primarily due to workforce reductions and lower employee long-term incentive costs driven by the decline in our share price, offset by

severance costs of approximately $43 million. Lower discretionary spending also contributed to the reduction of general and administration costs.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased $37 million in 2015 compared with 2014 as weakening of the Canadian dollar relative to the U.S. dollar increased interest incurred on our U.S. dollar denominated debt, partially offset by lower interest incurred on the Partnership Contribution Payable, which was repaid in the first quarter of 2014.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for 2015 was 5.3 percent (2014 – 5.0 percent).

Foreign Exchange

($ millions)	**2015**	2014	2013
Unrealized Foreign Exchange (Gain) Loss	**1,097**	411	40
Realized Foreign Exchange (Gain) Loss	**(61)**	-	168
	1,036	411	208

The majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar was 16 percent weaker at December 31, 2015 compared with December 31, 2014, resulting in an unrealized loss of $1,097 million.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in 2015 was $78 million (2014 – $83 million).

Income Tax

($ millions)	**2015**	2014	2013
Current Tax			
Canada	**586**	94	143
United States	**(12)**	(2)	45
Total Current Tax Expense (Recovery)	**574**	92	188
Deferred Tax Expense (Recovery)	**(655)**	359	244
	(81)	451	432

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

($ millions)	**2015**	2014	2013
Earnings Before Income Tax	**537**	1,195	1,094
Canadian Statutory Rate	**26.1%**	25.2%	25.2%
Expected Income Tax	**140**	301	276
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(41)**	(43)	87
Non-Deductible Stock-Based Compensation	**7**	13	10
Non-Taxable Capital Losses	**137**	74	6
Unrecognized Capital Losses Arising from Unrealized Foreign Exchange	**135**	50	25
Adjustments Arising From Prior Year Tax Filings	**(55)**	(16)	(13)
Derecognition (Recognition) of Capital Losses	**(149)**	(9)	15
Recognition of U.S. Tax Basis	**(415)**	-	-
Change in Statutory Rate	**161**	-	-
Foreign Exchange Gain (Loss) not Included in Net Earnings	-	(13)	19
Goodwill Impairment	-	125	-
Other	**(1)**	(31)	7
Total Tax	**(81)**	451	432
Effective Tax Rate	**(15.1)%**	37.7%	39.5%

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review and as a result, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

In 2015, current tax increased due to the sale of our royalty interest and mineral fee title lands business and the timing of recognition of partnership income for tax purposes. Of the $574 million of current tax, $391 million is attributed to the sale of the royalty interest and mineral fee title lands business.

We recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of our refining assets. The increase in tax basis was a result of our partner recognizing a taxable gain on its interest in WRB Refining LP ("WRB") which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. Additionally, the deferred tax recovery was due to the timing of recognition of partnership income, unrealized risk management losses, reversal of other temporary differences and current year operating losses. This was partially offset by a one-time charge of approximately $161 million from the revaluation of the deferred tax liability due to an increase in the Alberta corporate income tax rate from 10 percent to 12 percent on July 1, 2015.

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

Our effective tax rate for 2015 differs from the statutory rate due to an increase in tax basis of our U.S. assets, and the recognition of the benefit of capital losses, partially offset by non-deductible unrealized foreign exchange losses and a one-time deferred tax expense arising from the Alberta corporate income tax rate increase.

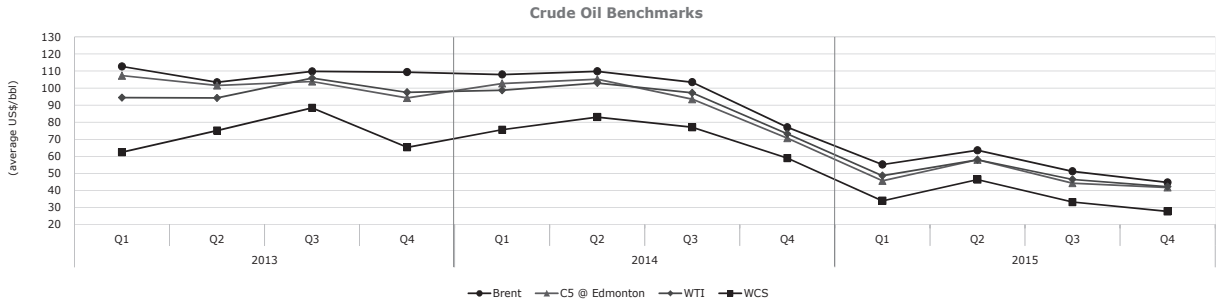
QUARTERLY RESULTS

Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices. Crude oil production in the fourth quarter of 2015 was six percent higher than in the fourth quarter of 2013, while and natural gas production decreased 18 percent from the fourth quarter of 2013. Our average crude oil and natural gas prices in the fourth quarter of 2015 were 53 percent and 13 percent lower compared with the fourth quarter of 2013.

($ millions, except per share amounts or where otherwise indicated)	**2015**				2014				2013
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1	Q4
Production Volumes									
Crude Oil (bbls/d)	**199,556**	**210,422**	**199,954**	**218,020**	216,177	199,089	201,688	196,854	188,743
Natural Gas (MMcf/d)	**424**	**430**	**450**	**462**	479	489	507	476	514
Refinery Operations									
Crude Oil Runs (Mbbls/d)	**405**	**394**	**441**	**439**	420	407	466	400	447
Refined Products (Mbbls/d)	**430**	**414**	**462**	**469**	442	429	489	420	469
Revenues	**2,924**	**3,273**	**3,726**	**3,141**	4,238	4,970	5,422	5,012	4,747
Operating Cash Flow [(1) (2)]	**357**	**602**	**932**	**548**	537	1,156	1,305	1,181	976
Cash Flow [(1)]	**275**	**444**	**477**	**495**	401	985	1,189	904	835
Per Share – Diluted	**0.33**	**0.53**	**0.58**	**0.64**	0.53	1.30	1.57	1.19	1.10
Operating Earnings (Loss) [(1)]	**(438)**	**(28)**	**151**	**(88)**	(590)	372	473	378	212
Per Share – Diluted	**(0.53)**	**(0.03)**	**0.18**	**(0.11)**	(0.78)	0.49	0.62	0.50	0.28
Net Earnings (Loss)	**(641)**	**1,801**	**126**	**(668)**	(472)	354	615	247	(58)
Per Share – Basic	**(0.77)**	**2.16**	**0.15**	**(0.86)**	(0.62)	0.47	0.81	0.33	(0.08)
Per Share – Diluted	**(0.77)**	**2.16**	**0.15**	**(0.86)**	(0.62)	0.47	0.81	0.33	(0.08)
Capital Investment [(3)]	**428**	**400**	**357**	**529**	786	750	686	829	898
Dividends									
Cash Dividends	**132**	**133**	**125**	**138**	201	201	201	202	183
In Shares from Treasury	**-**	**-**	**98**	**84**	-	-	-	-	-
Per Share	**0.16**	**0.16**	**0.2662**	**0.2662**	0.2662	0.2662	0.2662	0.2662	0.242

(1) Non-GAAP measure defined in this MD&A.
(2) For all periods presented, we reclassified employee long-term incentive costs from operating expenses to general and administrative costs. There were no changes to Cash Flow, Operating Earnings or Net Earnings.
(3) Includes expenditures on PP&E and E&E assets.

A substantial downward shift in the commodity price environment occurred late in 2014 and continued throughout 2015. Declining crude oil and refining benchmark prices impacted our fourth quarter financial results. Average Brent and WTI benchmark prices decreased 42 percent in the fourth quarter of 2015 compared with 2014, while the U.S. dollar average WCS price decreased 53 percent.



Fourth Quarter 2015 Results as Compared with the Fourth Quarter 2014

Production Volumes

Total crude oil production declined eight percent primarily due to expected natural declines, the sale of our royalty interest and mineral fee title lands business, and lower production at Foster Creek. Fourth quarter production was lower compared with 2014. Improved wellbore conformance accelerated production from more mature wells, resulting in faster declines from these wells. To preserve capital, we chose in 2015 to defer some planned well pads, which combined with the faster declines, contributed to lower fourth quarter volumes. In addition, while well downtime at Foster Creek was within expected ranges for 2015, a higher than average number of wells were down for servicing in the second half of the year, which further impacted production.

These reductions were partially offset by higher production at Christina Lake and from successful horizontal well performance in southern Alberta. Third-party royalty interest volumes prior to the divestiture in the third quarter were approximately 6,580 barrels of oil equivalent per day.

Natural gas production in the fourth quarter of 2015 decreased 11 percent due to expected natural declines. We continued to focus capital investment on high rate of return projects and directed the majority of our total capital investment to our crude oil properties.

Refinery Operations

Crude oil runs decreased and refined product output decreased as the planned turnaround at Wood River in 2015 was larger in scale than in 2014. In addition, our Wood River refinery experienced unplanned outages in the fourth quarter of 2015.

Revenue

Revenues decreased $1,314 million or 31 percent primarily due to:

- A decline in Refining and Marketing revenues of $743 million largely due a decrease in refined product prices, consistent with a 37 percent decline in average refined product benchmark prices, and lower refined product output;
- Crude oil and natural gas sales volumes decreasing two percent and 11 percent, respectively;
- Our average crude oil sales price (excluding financial hedging) decreasing 50 percent to $27.63 per barrel; and
- A decline in natural gas sales prices (excluding financial hedging) of 29 percent to $2.78 per Mcf.

The decreases to revenues were partially offset by:

- Crude oil royalties decreasing $68 million; and
- An increase in condensate volumes used for blending with our bitumen and heavy oil production.

Operating Cash Flow

Operating Cash Flow decreased $180 million, or 34 percent, in the three months ended December 31, 2015 compared with 2014. Upstream Operating Cash Flow decreased 54 percent due to lower crude oil and natural gas sales prices, and lower crude oil and natural gas sales volumes, partially offset by higher realized risk management gains and lower royalties due to a decrease in crude oil sales prices.

Refining and Marketing Operating Cash Flow increased by 88 percent to a loss of $40 million. The increase was due to improved margins on the sale of secondary products, weakening of the Canadian dollar relative to the U.S. dollar, an increase in average market crack spreads and lower refined product inventory impairments, partially offset by lower refined product output and higher operating costs.

Cash Flow

Cash Flow decreased $126 million or 31 percent in the fourth quarter of 2015 compared with 2014, primarily due to lower Operating Cash Flow, as discussed above, and an increase in our general and administrative expenses mainly driven by severance costs related to the previously announced workforce reductions, partially offset by a higher current income tax recovery.

Operating Earnings (Loss)

In the fourth quarter of 2015, our Operating Loss was $438 million compared with a loss of $590 million in the same period in 2014. The improvement was primarily due to no goodwill impairment in 2015 compared with a goodwill impairment of $497 million in 2014 and a higher income tax recovery, partially offset by lower Cash Flow and an increase in DD&A and exploration expense.

Net Earnings (Loss)

In 2015, our Net Loss included unrealized risk management losses of $26 million and non-operating foreign exchange losses of $212 million in addition to the Operating Loss discussed above. In 2014, our Net Loss was smaller due to unrealized risk management gains of $416 million, partially offset by a larger Operating Loss and non-operating foreign exchange losses of $186 million.

Capital Investment

Capital investment in the fourth quarter of 2015 was $428 million, a 46 percent decrease from the same period in 2014 primarily due to lower spending in our Oil Sands and Conventional segments. Capital investment was reduced with the intent of conserving cash and maintaining the strength of our balance sheet in light of the low commodity price environment.

OIL AND GAS RESERVES AND RESOURCES

We retain independent qualified reserves evaluators ("IQREs") to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, natural gas and coal bed methane ("CBM") reserves and 100 percent of our bitumen contingent and prospective resources producible with established technology.

The sale of our royalty interest and mineral fee title lands business had a minimal effect on our reserves, before royalties. However, our proved and proved plus probable reserves, after royalties, decreased by 27 MMBOE and 39 MMBOE, respectively.

Additional developments in 2015 compared with 2014 include:

- Proved bitumen reserves increasing 11 percent due to Christina Lake proved reserves additions of 234 million barrels from improved reservoir performance and regulatory approval of the Kirby East area expansion converting probable reserves to proved reserves;
- Proved plus probable bitumen reserves remaining constant due to improved reservoir performance at Foster Creek and Christina Lake offsetting production;
- Heavy oil proved reserves and proved plus probable reserves declining 15 percent and 21 percent, respectively. The decrease was due to the deferral of drilling at Pelican Lake, the impact of low crude oil prices and the loss of undeveloped reserves at Elk Point due to poor economics;
- Light and medium oil and NGLs proved reserves decreasing eight percent and proved plus probable reserves decreasing seven percent as production exceeded additions;
- Natural gas proved reserves declining nine percent and proved plus probable reserves decreasing 10 percent as additions and improved performance were more than offset by reductions due to production; and
- Bitumen best estimate economic contingent resources remaining flat at 9.3 billion barrels and bitumen best estimate prospective resources decreasing slightly to 7.4 billion barrels. Factors impacting the results include:
    - Reduced stratigraphic drilling yielding negligible contingent resources revisions; and
    - Minor mapping changes plus small lease expiries slightly reducing prospective resources.

The reserves and resources data that follows is presented as at December 31, 2015 using McDaniel & Associates Consultants Ltd.'s ("McDaniel's") January 1, 2016 forecast prices and inflation. Comparative information as at December 31, 2014 uses McDaniel's January 1, 2015 forecast prices and inflation.

Reserves

As at December 31, (before royalties)	**Bitumen** (MMbbls)		**Heavy Oil** (MMbbls)		**Light and Medium Oil & NGLs** (MMbbls)		**Natural Gas & CBM** (Bcf)	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Proved	**2,183**	1,970	**133**	156	**110**	120	**721**	796
Probable	**1,115**	1,330	**87**	123	**44**	46	**232**	260
Proved plus Probable	**3,298**	3,300	**220**	279	**154**	166	**953**	1,056

Reconciliation of Proved Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2014	**1,970**	**156**	**120**	**796**
Extensions and Improved Recovery	**188**	**-**	**1**	**8**
Technical Revisions	**76**	**(10)**	**1**	**79**
Economic Factors	**-**	**-**	**(1)**	**(1)**
Production [1]	**(51)**	**(13)**	**(11)**	**(161)**
December 31, 2015	**2,183**	**133**	**110**	**721**
Year Over Year Change	**213**	**(23)**	**(10)**	**(75)**
	11%	**(15)%**	**(8)%**	**(9)%**

(1) Production includes the natural gas used as a fuel source in our oil sands operations and excludes royalty interest production.

Reconciliation of Probable Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
December 31, 2014	**1,330**	**123**	**46**	**260**
Extensions and Improved Recovery	**-**	**-**	**1**	**7**
Technical Revisions	**(215)**	**(36)**	**(4)**	**(36)**
Economic Factors	**-**	**-**	**1**	**1**
December 31, 2015	**1,115**	**87**	**44**	**232**
Year Over Year Change	**(215)**	**(36)**	**(2)**	**(28)**
	(16)%	**(29)%**	**(4)%**	**(11)%**

Economic Contingent Resources and Prospective Resources

As at December 31, (billions of barrels, before royalties)	Bitumen 2015	Bitumen 2014
Economic Contingent Resources [1]		
Best Estimate	**9.3**	9.3
Prospective Resources [1] [2]		
Best Estimate	**7.4**	7.5

(1) See Oil and Gas Information in the Advisory for definitions of contingent resources, economic contingent resources, prospective resources and best estimates. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(2) There is uncertainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources. Prospective resources are not screened for economic viability.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), and material risks and uncertainties associated with estimates of reserves and contingent and prospective resources is contained in our AIF for the year ended December 31, 2015. Further information with respect to contingent and prospective 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 ("Resources Statement"). Both our AIF and Resources Statement are available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2015	2014	2013
Net Cash From (Used In)			
Operating Activities	**1,474**	3,526	3,539
Investing Activities	**888**	(4,350)	(1,519)
Net Cash Provided (Used) Before Financing Activities	**2,362**	(824)	2,020
Financing Activities	**894**	(797)	(726)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(34)**	52	(2)
Increase (Decrease) in Cash and Cash Equivalents	**3,222**	(1,569)	1,292

As at December 31,	2015	2014	2013
Cash and Cash Equivalents	**4,105**	883	2,452
Committed and Undrawn Credit Facilities	**4,000**	3,000	3,000

Operating Activities

Cash from operating activities decreased in 2015 mainly due to lower Cash Flow, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $4,337 million at December 31, 2015 compared with $772 million at December 31, 2014. Working capital increased due to cash proceeds received on the sale of our royalty interest and mineral fee title lands business in July of 2015 and the common share issuance in the first quarter of 2015.

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

Investing Activities

Cash from investing activities in 2015 was primarily due to the divestiture of our royalty interest and mineral fee title lands business in 2015. In 2014, cash used by investing activities related to the repayment of the US$1.4 billion Partnership Contribution Payable. Lower capital expenditures in 2015 also contributed to the increase in cash from investing activities.

Financing Activities

Cash provided by financing activities increased in 2015 primarily due to net proceeds from our common share issuance and cash savings from our DRIP. We issued 67.5 million common shares at a price of $22.25 per share for net proceeds of $1.4 billion in the first quarter of 2015. We plan to use the net proceeds to partially fund our capital expenditure program for 2016 and for general corporate purposes.

In 2015, we paid dividends of $0.8524 per share or $710 million, of which $528 million was paid in cash and $182 million was reinvested in common shares through our DRIP (2014 – $1.0648 per share or $805 million paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Our long-term debt at December 31, 2015 was $6,525 million (December 31, 2014 – $5,458 million) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $1,067 million increase in long-term debt is due to weakening of the Canadian dollar relative to the U.S. dollar.

As at December 31, 2015, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

We expect cash flow from our crude oil, natural gas and refining operations to fund a portion of our cash requirements. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

The following sources of liquidity are available at December 31, 2015:

($ millions)	Amount	Term
Cash and Cash Equivalents	**4,105**	**Not applicable**
Committed Credit Facility	**1,000**	**November 2017**
Committed Credit Facility	**3,000**	**November 2019**
U.S. Base Shelf Prospectus (1)	**US$2,000**	**July 2016**
Canadian Base Shelf Prospectus (1)	**1,500**	**July 2016**

(1) Availability is subject to market conditions.

Committed Credit Facility

In 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, we had $4.0 billion available on our committed credit facility.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent; we are well below this limit.

U.S. and Canadian Base Shelf Prospectuses

On June 24, 2014, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion, which replaced the U.S. base shelf prospectus dated June 6, 2012, as amended May 9, 2013. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue.

On June 25, 2014, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion, which replaced the Canadian base shelf prospectus dated May 24, 2012. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue.

As at December 31, 2015, no notes were issued under the existing U.S. or Canadian base shelf prospectuses.

It is our intention to file a new prospectus prior to the maturity of the existing prospectuses.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, goodwill and asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing twelve-month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

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

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

Debt to Capitalization and Net Debt to Capitalization are calculated as follows:

As at December 31,	**2015**	2014	2013
Debt	**6,525**	5,458	4,997
Shareholders' Equity	**12,391**	10,186	9,946
Capitalization	**18,916**	15,644	14,943
Debt to Capitalization	**34%**	35%	33%
Net Debt [(1)]	**2,420**	4,575	4,070
Shareholders' Equity	**12,391**	10,186	9,946
Capitalization	**14,811**	14,761	14,016
Net Debt to Capitalization	**16%**	31%	29%

(1) Net Debt is defined as Debt and the current and long-term portions of the Partnership Contribution Payable, net of cash and cash equivalents.

The following is a reconciliation of Adjusted EBITDA, and the calculations of Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA:

As at December 31,	**2015**	2014	2013
Debt	**6,525**	5,458	4,997
Net Debt [(1)]	**2,420**	4,575	4,070
Adjusted EBITDA			
Net Earnings	**618**	744	662
Add (Deduct):			
Finance Costs	**482**	445	529
Interest Income	**(28)**	(33)	(96)
Income Tax Expense	**(81)**	451	432
DD&A	**2,114**	1,946	1,833
Goodwill Impairment	**-**	497	-
E&E Impairment	**138**	86	50
Unrealized (Gain) Loss on Risk Management	**195**	(596)	415
Foreign Exchange (Gain) Loss, Net	**1,036**	411	208
(Gain) Loss on Divestiture of Assets	**(2,392)**	(156)	1
Other (Income) Loss, Net	**2**	(4)	2
	2,084	3,791	4,036
Debt to Adjusted EBITDA	**3.1x**	1.4x	1.2x
Net Debt to Adjusted EBITDA	**1.2x**	1.2x	1.0x

(1) Net Debt is defined as Debt and the current and long-term portions of the Partnership Contribution Payable, net of cash and cash equivalents.

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

Share Capital and Stock-Based Compensation Plans

As at December 31, 2015, there were approximately 833 million common shares outstanding (December 31, 2014 – 757 million common shares). Cenovus issued 76.2 million common shares in 2015, including 8.7 million shares issued under the DRIP and 67.5 million shares issued related to the common share issuance in the first quarter of 2015.

The DRIP permits shareholders to reinvest their dividends into additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. In the first half of 2015, participants in our DRIP were issued shares from treasury at a three percent discount to the average market price, as defined in the DRIP; this resulted in cash savings of $177 million. For the second half of the year, common shares acquired by the DRIP were purchased on the open market. Refer to cenovus.com for more details.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 27 of the Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at January 31, 2016	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**43,660**	**25,892**
Other Stock-Based Compensation Plans	**10,257**	**1,488**

Contractual Obligations and Commitments

We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements and operating leases on buildings. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans.

The below contractual obligations have been grouped as operating, investing and financing, relating to the type of cash outflow that will arise:

	Expected Payment Date						
($ millions)	2016	2017	2018	2019	2020	Thereafter	**Total**
Operating							
Transportation and Storage [1]	702	715	780	774	901	23,537	**27,409**
Operating Leases (Building Leases)	116	120	156	153	151	2,647	**3,343**
Product Purchases	84	3	-	-	-	-	**87**
Other Long-term Commitments	45	31	24	26	15	125	**266**
Interest on Long-term Debt	349	349	349	349	247	4,193	**5,836**
Decommissioning Liabilities	34	28	28	30	36	6,509	**6,665**
Total Operating	1,330	1,246	1,337	1,332	1,350	37,011	**43,606**
Investing							
Capital Commitments	61	14	4	-	-	-	**79**
Total Investing	61	14	4	-	-	-	**79**
Financing							
Long-term Debt (principal only)	-	-	-	1,799	-	4,775	**6,574**
Total Financing	-	-	-	1,799	-	4,775	**6,574**
Total Payments [2]	1,391	1,260	1,341	3,131	1,350	41,786	**50,259**
Fixed Price Product Sales	55	3	-	-	-	-	**58**

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Contracts on behalf of FCCL Partnership ("FCCL") and WRB are reflected at our 50 percent interest.

As operator of Foster Creek, Christina Lake and Narrows Lake, we are responsible for the field operations, marketing and transportation of 100 percent of the production from these assets. We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the Consolidated Financial Statements.

Commitments for various firm pipeline transportation agreements were $27 billion, consistent with 2014. Reduced obligations from changes to TransCanada's proposed Energy East pipeline were offset by increases to our U.S. dollar commitments due to the weakening of the Canadian dollar relative to the U.S. dollar, and higher costs and tolls on existing commitments.

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

As at December 31, 2015, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 29 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 11 Bcf of natural gas, at a weighted average price of $4.94 per Mcf.

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

Legal Proceedings

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

Related Party Transactions

Cenovus did not enter into any related party transactions during the years ended December 31, 2015 or 2014, except for our key management compensation. A summary of key management compensation can be found in the notes to the Consolidated Financial Statements.

RISK MANAGEMENT

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of risk across Cenovus.

Risk Governance

The ERM Policy, approved by our Board, outlines our risk management principles and expectations, as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established Risk Management Practices, a Risk Management Framework and Risk Assessment Tools. Our Risk Management Framework contains the key attributes recommended by the International Standards Organization ("ISO") in its *ISO 31000 – Risk Management Principles and Guidelines*. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through quarterly updates.

Risk Assessment

All risks are assessed for their potential impact on the achievement of Cenovus's strategic objectives as well as their likelihood of occurring. Risks are analyzed through the use of a Risk Matrix and other standardized risk assessment tools.

Using a Risk Matrix, each risk is classified on a continuum ranging from "Low" to "Extreme". Risks are first evaluated on an inherent basis, without considering the presence of controls or mitigating measures. Risks are then re-evaluated based on their residual risk ranking, reflecting the exposure that remains after implemented mitigation and control measures are considered.

Management determines if additional risk treatment is required based on the residual risk ranking. There are prescribed actions for escalating and communicating risk to the right decision makers.

Significant Risk Factors

The following discussion describes the financial, operations and regulatory risks relating to Cenovus and our operations. A description of the risk factors and uncertainties can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2015.

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. From time to time, Management may enter into contracts to mitigate risk associated with fluctuations of commodity prices, interest rates and foreign exchange rates.

Commodity Prices

Fluctuations in commodity prices and refined product prices impacts our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

Crude oil and natural gas prices are impacted by a number of factors including global and regional supply and demand and economic conditions, the actions of OPEC, government regulation, political stability, transportation constraints, weather conditions and availability of alternative fuels, all of which are beyond our control and can result in a high degree of price volatility. Changing prices will affect the revenues generated by the sale of our production. Our financial performance is also affected by price differentials since our upstream production differs in quality and location from underlying benchmark commodity prices quoted on financial exchanges.

Commodity prices began to decline in the fourth quarter of 2014 and have remained low, resulting in an impairment to the carrying value of some of our assets. If crude oil and natural gas prices continue to decline significantly and remain at low levels for an extended period of time, future capital spending could be reduced causing projects to be impaired, delayed or cancelled, and production could be curtailed or suspended, among other impacts.

Refined product prices are affected by several factors including global supply and demand for refined products, weather conditions, and planned and unplanned refinery maintenance, all of which are beyond our control and can result in a high degree of price volatility. The financial performance of our refining operations is also impacted by margin volatility due to fluctuations in the supply and demand for refined products, crude oil costs and seasonal factors when production changes to match seasonal demand.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3 and 32 to the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	2015			2014		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(571)**	**123**	**(448)**	(37)	(536)	(573)
Natural Gas	**(59)**	**55**	**(4)**	(7)	(55)	(62)
Refining	**(36)**	**10**	**(26)**	(26)	(11)	(37)
Power	**10**	**5**	**15**	4	6	10
Interest Rate	**-**	**2**	**2**	-	-	-
(Gain) Loss on Risk Management	**(656)**	**195**	**(461)**	(66)	(596)	(662)
Income Tax Expense (Recovery)	**175**	**(54)**	**121**	20	152	172
(Gain) Loss on Risk Management, After Tax	**(481)**	**141**	**(340)**	(46)	(444)	(490)

In 2015, we recorded realized gains on crude oil and natural gas risk management activities, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized losses on our crude oil and natural gas financial instruments primarily due to the realization of settled positions partially offset by changes in market prices.

Commodity Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. Fluctuations in commodity prices could have resulted in unrealized gains (losses) for the year on open risk management positions as at December 31, 2015 as follows:

Commodity	**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)**

Risks Associated with Derivative Financial Instruments

Financial instruments expose Cenovus to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Credit Policy.

Financial instruments also expose Cenovus to the risk of a loss from adverse changes in the market value of financial instruments or if we're unable to fulfill our delivery obligations related to the underlying physical

transaction. Financial instruments may limit the benefit to Cenovus if commodity price increases. These risks are minimized through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

Liquidity

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due or be unable to liquidate assets in a timely manner at a reasonable price. In declining economic times, such as the low commodity price environment in which we are currently operating, or due to unforeseen events, our liquidity risk could become heightened.

Liquidity risk is further impacted by the amount and timing of financial and operating commitments, future capital expenditures, debt repayments as well as available sources of liquidity, which may be impacted by our credit ratings. If we were unable to meet our financial obligations as they became due or be unable to liquidate assets in a timely manner at a reasonable price, this could have a material adverse effect on our financial condition, results of operations, cash flows, access to capital, ability to comply with various financial and operating covenants, credit ratings and reputation.

We manage our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital including, but not limited to, cash and cash equivalents, cash from operating activities, undrawn credit facilities and availability under our shelf prospectuses. At December 31, 2015, we had cash and cash equivalents of $4.1 billion. No amounts were drawn on our $4.0 billion committed credit facility. In addition, we had $1.5 billion in unused capacity under our Canadian base shelf prospectus and US$2.0 billion in unused capacity under our U.S. base shelf prospectus, the availability of which is dependent on market conditions and our credit ratings. We intend to file a new prospectus prior to the maturity of the existing prospectuses.

Foreign Exchange Rates

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

Operational Risk

Operational risks are those risks that affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the oil and gas and refining industries. To partially mitigate our risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System ("COMS") to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition to leveraging COMS, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

Market Access and Transportation Restrictions

Cenovus's production is transported through pipelines and by rail and its refineries are reliant on pipelines to receive feedstock. Disruptions in, or restricted availability of pipeline service or rail shipments, could adversely affect our crude oil and natural gas sales, projected production growth, refining operations and cash flows. Insufficient transportation capacity for our production will impact our ability to efficiently access end markets. This may negatively impact our financial performance by way of higher transportation costs, wider price differentials, lower sales prices at specific locations or for specific grades of crude oil, and in extreme situations, production curtailment.

Operational Outages and Major Environmental or Safety Incidents

Our crude oil and natural gas production activities are subject to inherent operational risks such as encountering unexpected formations or pressures, blowouts, equipment failures and other accidents, interdependence of component systems, sour gas releases, uncontrollable flows of crude oil, natural gas or well fluids, adverse weather conditions, pollution and other environmental risks. Our refining and marketing activities are subject to risks including slowdowns due to equipment failure or transportation disruptions, weather, fires, explosions, railcar incidents or derailments, unavailability of feedstock, and poor price and quality of feedstock. Cenovus's operations could also be interrupted by natural disasters or other events beyond our control.

Failure to manage these risks effectively could result in potential fatalities, serious injury, asset damage or environmental impacts, any of which could have a material adverse effect on our reputation, financial condition, results of operations and cash flows. Cenovus does not insure against all potential occurrences and disruptions and our insurance may be insufficient to cover any such occurrences or disruptions.

Project Execution

There are risks associated with the execution and operations of our upstream and refining growth and development projects. Successful project execution will be highly dependent upon the availability and cost of materials,

equipment and skilled labour, our ability to finance growth and general economic conditions. Project execution will also be impacted by our ability to obtain the necessary environmental and regulatory approvals, and the effect of changing government regulations and public expectations in relation to the impact of oil sands development on the environment. The commissioning and integration of new facilities within our existing asset base could also cause delays in achieving targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows.

Cost Management

Our operating costs could escalate and become uncompetitive due to labour costs, equipment limitations, commodity prices, higher steam-to-oil ratios in our oil sands operations, additional government or environmental regulations and general inflationary pressures. Operating costs associated with our crude oil production are largely fixed in the short-term and, as a result, are largely dependent on levels of production. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Reserves Replacement

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

Leadership and Talent

Our success in executing our business strategy is dependent upon Management and their leadership capabilities, as well as, the quality and competency of our employees. If we fail to retain critical talent or are unsuccessful in attracting and retaining new talent, with the necessary leadership traits, skills and technical competencies, it could have a materially adverse effect on Cenovus's results of operations, pace of growth and financial condition.

Regulatory Risk

Regulatory risk is the risk of loss or lost opportunity resulting from the introduction of, or changes in, regulatory requirements or the failure to secure regulatory approval for a crude oil or natural gas development project. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects as well as result in compliance costs, adversely impacting our financial condition, results of operations and cash flows.

Regulatory Approvals

Our operations are subject to regulation and intervention by governments in areas such as energy policies, environmental and safety policies, land tenure, taxes, royalties, government fees, the export of crude oil, natural gas and other products, production rates, expropriation or cancellation of contract rights, acquisition of exploration and production rights, and control over the development and abandonment of fields. Changes to government regulation could impact Cenovus's existing and planned projects or increase capital investment or operating expenses, adversely impacting our financial condition, results of operations and cash flows.

Royalty Regimes

The governments of Alberta and Saskatchewan receive royalties on the production of crude oil and natural gas from lands where they own the mineral rights. The Government of Alberta released its royalty review report on January 29, 2015. The report recommends no changes to existing oil sands royalty rates but recommended further government-industry consultation on administrative aspects of the oil sands royalty regime. The royalty review report recommended a modernization of Alberta's conventional oil and gas royalty regime but did not provide details. The changes proposed to conventional oil and gas royalties will require further consultation between industry and government to fully understand their impacts. These changes to the Alberta provincial royalty structure could have a significant impact on Cenovus's financial condition, results of operations and cash flows. An increase in the royalty rates applicable in one or both provinces could make, in the respective province, future capital expenditures or existing operations uneconomic.

Environmental Regulations

Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances in the environment. They also impose restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations can require significant expenditures, including clean-up costs and damages arising from contaminated properties. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations.

Failure to comply with environmental regulations may result in the imposition of fines, penalties and environmental protection orders. The costs of complying with environmental regulations in the future may have a material adverse effect on our financial condition, results of operations and cash flows. Non-compliance with environmental regulations could have an adverse impact on Cenovus's reputation. There is also a risk that Cenovus could face litigation initiated by third parties relating to climate change or other environmental regulations.

Species at Risk Act

The Canadian federal legislation, Species at Risk Act, and provincial counterparts regarding threatened or endangered species may influence development in areas identified as critical habitat for species of concern (e.g. woodland caribou). In Alberta, the Alberta Caribou Action and Range Planning Project has been established to develop range plans and action plans with a view to achieving the maintenance and recovery of Alberta's 15 caribou populations. The federal and/or provincial implementation of measures to protect species at risk such as woodland caribou and their critical habitat in areas of Cenovus's current or future operations may limit our pace and amount of development and, in some cases, may result in an inability to operate in affected areas.

Climate Change

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants. In November, 2015, the Government of Alberta announced its climate leadership plan (the "CLP") highlighting four key strategies that the government will implement to address climate change: (1) the complete phase-out of coal-fired sources of electricity by 2030; (2) an Alberta economy-wide price on GHG emissions of $30/tonne; (3) capping oil sands emissions to a province-wide total of 100 megatonnes per year, with certain exceptions for cogeneration power sources and new upgrading capacity; and (4) reducing methane emissions from oil and gas activities by 45 percent by 2025.

We are also subject to the Specified Gas Emitters Regulation (the "SGER"), which imposes GHG emissions intensity limits and reduction requirements for owners of facilities that emit 100,000 tonnes per year or more of GHG. Recent amendments to the SGER have increased the maximum emission intensity reduction requirement for facility owners from 12 percent to 15 percent in 2016 and 20 percent starting in 2017. One of the options for complying with the SGER is for facility owners to purchase technology fund credits. The SGER amendments have increased the price for such credits from $15/tonne to $20/tonne for 2016 and $30/tonne beginning in 2017.

If comprehensive GHG regulation is enacted in Alberta or any jurisdiction in which we operate, including legislation to implement the CLP, and as a result of the amendments to the SGER, we may incur increased compliance costs, loss of markets, permitting delays, substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses and reduce demand for crude oil, natural gas and certain refined products.

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

Water Licenses

To operate our SAGD facilities we rely on water, which is obtained under licenses issued through the Alberta Water Act. Currently, we are not required to pay for the water we use under these licenses. If a change under these licenses reduces the amount of water available for our use, our production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of our projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us or at all, or that such additional water will in fact be available to divert under such licenses.

Alberta's Land-Use Framework

The Government of Alberta approved the Lower Athabasca Regional Plan ("LARP"), which identifies legally binding management frameworks for air, land and water that will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Uncertainty exists with respect to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation. This may have a material adverse effect on our financial condition, results of operations and cash flows. Additional regional plans are in the process of being developed by the Government of Alberta and no assurances can be given that such plans, if approved and implemented, will not materially impact our operations or future operations.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed

annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our Consolidated Financial Statements.

Joint Arrangements

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB. As a result, these joint arrangements are classified as joint operations and our share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, "*Joint Arrangements*", we considered the following:

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

Exploration and Evaluation Assets

The application of Cenovus's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and Cenovus's internal approval process.

Identification of CGUs

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of Cenovus's upstream, refining, crude-by-rail and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling

price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test and DD&A expense of our crude oil and natural gas assets in the Oil Sands and Conventional segments. Cenovus's crude oil and natural gas reserves are evaluated annually and reported to Cenovus by IQREs. Refer to the Outlook section of this MD&A for more details on future commodity prices.

Impairment of Assets

Impairment calculations require the use of estimates and assumptions, which are subject to change as new information becomes available. For our upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses, and income tax rates. Recoverable amounts for the our refining assets and crude-by-rail terminal use assumptions such as throughput, forward commodity prices, operating expenses, transportation capacity, supply and demand conditions, and income tax rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Refer to the Outlook section of this MD&A for more details on future commodity prices and to the reportable segments section of this MD&A for more details on impairments.

As at December 31, 2015, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal. Key assumptions in the determination of cash flows from reserves include crude oil and natural gas prices, and the discount rate. All reserves have been evaluated at December 31, 2015 by IQREs.

Crude Oil and Natural Gas Prices

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

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

(1) 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 IQREs 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.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of our upstream crude oil and natural gas assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgement to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. Refer to Note 22 of the Consolidated Financial Statements for more details on changes to decommissioning costs.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods. Refer to the Corporate and Eliminations section of this MD&A for more details on changes to estimates related to income taxes.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during 2015.

Future Accounting Pronouncements

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2016 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2015. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

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 International Accounting Standard 11, "*Construction Contracts*", International Accounting Standard 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

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. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements.

Financial Instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39").

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. We do not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, has assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2015. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2015.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2015. There have been no changes to ICFR during the year ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and integrating our corporate responsibility principles in the way we conduct our business. Our Corporate Responsibility ("CR") policy guides our activities in the areas of: Leadership; Corporate Governance and Business Practices; People; Environmental Performance; Stakeholder and Aboriginal Engagement; and Community Involvement and Investment.

We published our 2014 CR report in June 2015, detailing our efforts to accelerate our environmental performance, protect the health and safety of our staff, invest in and engage with the communities where we operate and maintain the highest standards of corporate governance. Our CR report also lists external recognition we received for our commitment to corporate responsibility and our efforts to balance economic, governance, social and environmental performance. Our CR policy and CR report are available on our website at cenovus.com.

OUTLOOK

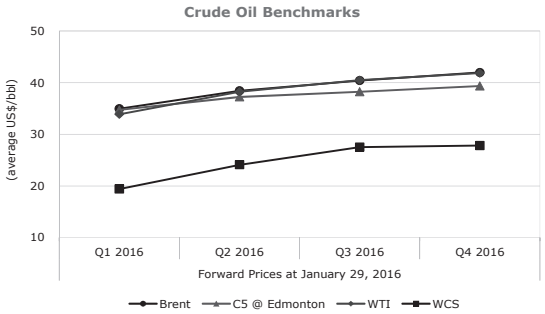
We expect 2016 will be another challenging year for our industry. Maintaining our financial resilience remains a top priority. Our revised 2016 guidance reflects reduced capital spending plans, consistent with our expectation that commodity prices will continue to be low for a prolonged period of time.

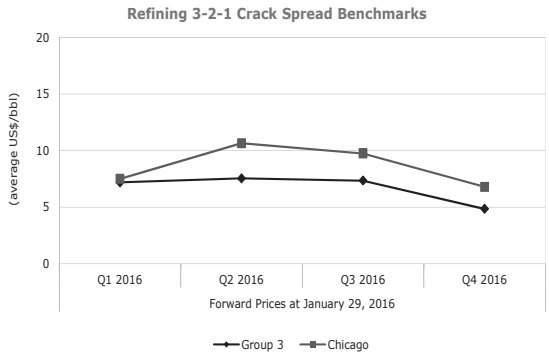
The following outlook commentary is focused on the next 12 months.

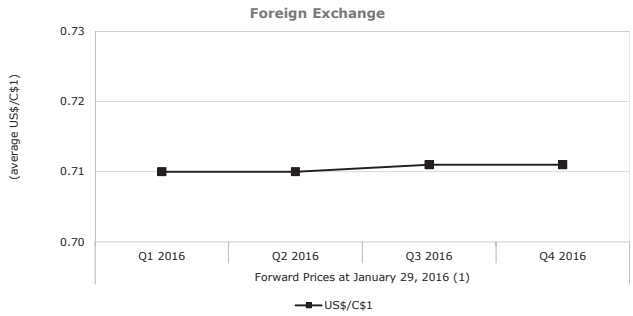
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment and the pace of growth of the global economy. Overall, we expect crude oil price volatility and a modest price improvement in 2016. Slower global supply growth, combined with annual increases in demand growth, should support prices in the second half of the year, constrained by the need to draw down surplus crude oil inventories and anticipated re-entry of Iranian crude oil into markets. We continue to anticipate slower supply growth from North American producers as a result of the significant reductions in capital spending. The low crude oil price environment also serves to help boost global economic momentum.
  We believe there is a risk that OPEC will attempt to gain market share by increasing rig counts or increasing OPEC production, which will depress crude oil prices, and that economic uncertainty in China may slow emerging market demand;
- We expect the Brent-WTI differential to remain narrow now that the U.S. has lifted restrictions on exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs. The Brent-WTI differential is expected to remain volatile due to mismatches in demand, global imports and refinery turnarounds; and
- We also expect that the WTI-WCS differential will remain wide due to additional Canadian supply growth and declining U.S. light tight oil supply. However, substantially wider differentials are unlikely due to excess rail capacity and further expansions on existing pipeline systems.







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

Refining crack spreads in 2016, as forecasted at January 29, 2016, are expected to strengthen late in the second quarter due to higher seasonal demand for refined products and then decline in the second half of the year.

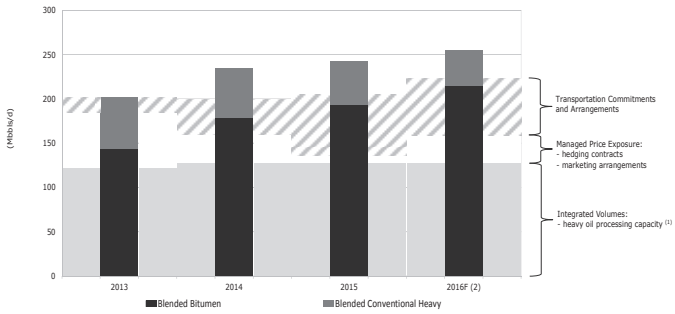
Natural gas production is anticipated to increase marginally in 2016 due to low levels of drilling activity. However, warmer weather is expected to reduce residential and commercial demand, while coal-to-gas substitution in the power sector is expected to continue. As a result, natural gas prices are anticipated to remain weak through the first half of 2016.

The average foreign exchange forward price expected over the next 12 months is US$0.711/C$. We expect that the Canadian dollar, compared with the U.S. dollar, will remain relatively weak in the near term due to weak commodity prices and Canadian economic uncertainty. Overall, a weak Canadian dollar should have a positive impact on our revenues and Operating Cash Flow.

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

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

Protection Against Canadian Congestion



(1) Expected gross production capacity.
(2) Excludes additional 18,000 bbls/d heavy oil capacity expected as a result of the Wood River debottlenecking project (expected in the second half of 2016).

Key Priorities for 2016

Maintain Financial Resilience

Maintaining our financial resilience continues to be a top priority. At December 31, 2015, we had $4.1 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 16 years, with no debt maturing until the fourth quarter of 2019. We also have Canadian and U.S. base shelf prospectuses, the availability of which is dependent on market conditions and our credit ratings. Although we have a strong balance sheet, we plan to undertake additional measures in 2016 to remain financially resilient, including reductions in capital, operating and general and administrative costs, as we anticipate commodity prices to remain low in the upcoming year.

Attack Cost Structures

We will continue to focus on reducing our cost structure. In 2015, we captured savings of approximately $540 million, relative to our budget, from capital, operating and general and administrative cost reductions. We believe approximately 60 percent of these cost savings are sustainable over the long term and were reflected in our original 2016 budget.

We believe we are positioned to achieve additional sustainable cost reductions going forward. We anticipate capital investment in 2016 of $1.2 billion to $1.3 billion, a reduction of $200 million to $300 million from our original budget announced in December 2015. We are targeting $100 million to $200 million of further savings in operating, general and administrative and compensation costs. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure, and maximize the strengths of our functional business model.

Disciplined and Value-added Growth

We are committed to exercising capital discipline. We will consider expanding existing projects and developing emerging opportunities only when we believe we will generate attractive potential returns for shareholders. Although we have some of the needed fiscal and regulatory clarity at the provincial level, additional certainty around federal fiscal and regulatory regimes, commodity prices and our ability to sustain cost reductions is required. We will only commit to project reactivation if it does not undermine the strength of our balance sheet.

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Report of Management

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of four independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States *Sarbanes – Oxley Act of 2002* and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets with Management and the independent auditors on at least a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

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

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2015. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at December 31, 2015.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2015, as stated in their Report of Independent Registered Public Accounting Firm dated February 10, 2016. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Brian C. Ferguson

Brian C. Ferguson
President &
Chief Executive Officer
Cenovus Energy Inc.

/s/ Ivor M. Ruste

Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

February 10, 2016

Report of Independent Registered Public Accounting Firm

To the Shareholders of Cenovus Energy Inc.

We have audited the accompanying Consolidated Balance Sheets of Cenovus Energy Inc. as of December 31, 2015 and December 31, 2014 and the Consolidated Statements of Earnings, Comprehensive Income, Shareholders' Equity and Cash Flows for each of the years in the three-year period ended December 31, 2015. We also have audited Cenovus Energy Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Management is responsible for these Consolidated Financial Statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Report of Management. Our responsibility is to express an opinion on these Consolidated Financial Statements and an opinion on Cenovus Energy Inc.'s internal control over financial reporting based on our integrated audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the Consolidated Financial Statements included examining, on a test basis, evidence supporting the amounts and disclosures in the Consolidated Financial Statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall Consolidated Financial Statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that: (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of Cenovus Energy Inc. as of December 31, 2015 and December 31, 2014 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also, in our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control – Integrated Framework (2013) issued by COSO.

/s/ Pricewaterhouse Coopers LLP

PricewaterhouseCoopers LLP
Chartered Professional Accountants
Calgary, Alberta, Canada

February 10, 2016

CONSOLIDATED STATEMENTS OF EARNINGS

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

	Notes	**2015**	2014	2013
Revenues	1			
Gross Sales		**13,207**	20,107	18,993
Less: Royalties		**143**	465	336
		13,064	19,642	18,657
Expenses	1			
Purchased Product		**7,374**	10,955	10,399
Transportation and Blending		**2,043**	2,477	2,074
Operating		**1,839**	2,045	1,782
Production and Mineral Taxes		**18**	46	35
(Gain) Loss on Risk Management	31	**(461)**	(662)	293
Depreciation, Depletion and Amortization	9,16	**2,114**	1,946	1,833
Goodwill Impairment	9	**-**	497	-
Exploration Expense	9,15	**138**	86	114
General and Administrative		**335**	379	365
Finance Costs	5	**482**	445	529
Interest Income	6	**(28)**	(33)	(96)
Foreign Exchange (Gain) Loss, Net	7	**1,036**	411	208
Research Costs		**27**	15	24
(Gain) Loss on Divestiture of Assets	8	**(2,392)**	(156)	1
Other (Income) Loss, Net		**2**	(4)	2
Earnings Before Income Tax		**537**	1,195	1,094
Income Tax Expense (Recovery)	10	**(81)**	451	432
Net Earnings		**618**	744	662
Net Earnings Per Share	11			
Basic		**$0.75**	$0.98	$0.88
Diluted		**$0.75**	$0.98	$0.87

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31,
($ millions)

	Notes	**2015**	2014	2013
Net Earnings		**618**	744	662
Other Comprehensive Income (Loss), Net of Tax	26			
Items That Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**20**	(18)	14
Items That May be Reclassified to Profit or Loss:				
Change in Value of Available for Sale Financial Assets		**6**	-	10
Foreign Currency Translation Adjustment		**587**	215	117
Total Other Comprehensive Income, Net of Tax		**613**	197	141
Comprehensive Income		**1,231**	941	803

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	**2015**	2014
Assets			
Current Assets			
Cash and Cash Equivalents	12	**4,105**	883
Accounts Receivable and Accrued Revenues	13	**1,251**	1,582
Income Tax Receivable		**6**	28
Inventories	14	**810**	1,224
Risk Management	31,32	**301**	478
Current Assets		**6,473**	4,195
Exploration and Evaluation Assets	1,15	**1,575**	1,625
Property, Plant and Equipment, Net	1,16	**17,335**	18,563
Income Tax Receivable		**90**	-
Other Assets	18	**76**	70
Goodwill	1,19	**242**	242
Total Assets		**25,791**	24,695
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	20	**1,702**	2,588
Income Tax Payable		**133**	357
Risk Management	31,32	**23**	12
Current Liabilities		**1,858**	2,957
Long-Term Debt	21	**6,525**	5,458
Risk Management	31,32	**7**	4
Decommissioning Liabilities	22	**2,052**	2,616
Other Liabilities	23	**142**	172
Deferred Income Taxes	10	**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
Commitments and Contingencies	34		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

/s/ Michael A. Grandin

Michael A. Grandin
Director
Cenovus Energy Inc.

/s/ Colin Taylor

Colin Taylor
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)

	Share Capital (Note 25)	Paid in Surplus (Note 25)	Retained Earnings	AOCI [1] (Note 26)	Total
Balance as at December 31, 2012	3,829	4,154	1,730	69	9,782
Net Earnings	-	-	662	-	662
Other Comprehensive Income (Loss)	-	-	-	141	141
Total Comprehensive Income (Loss)	-	-	662	141	803
Common Shares Issued Under Stock Option Plans	31	-	-	-	31
Common Shares Cancelled	(3)	3	-	-	-
Stock-Based Compensation Expense	-	62	-	-	62
Dividends on Common Shares	-	-	(732)	-	(732)
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.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	**2015**	2014	2013
Operating Activities				
Net Earnings		**618**	744	662
Depreciation, Depletion and Amortization	9,16	**2,114**	1,946	1,833
Goodwill Impairment	9	**-**	497	-
Exploration Expense	9,15	**138**	86	50
Deferred Income Taxes	10	**(655)**	359	244
Unrealized (Gain) Loss on Risk Management	31	**195**	(596)	415
Unrealized Foreign Exchange (Gain) Loss	7	**1,097**	411	40
(Gain) Loss on Divestiture of Assets	8	**(2,392)**	(156)	1
Current Tax on Divestiture of Assets	8	**391**	-	-
Unwinding of Discount on Decommissioning Liabilities	5,22	**126**	120	97
Other		**59**	68	267
Net Change in Other Assets and Liabilities		**(107)**	(135)	(120)
Net Change in Non-Cash Working Capital		**(110)**	182	50
Cash From Operating Activities		**1,474**	3,526	3,539
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	15	**(138)**	(279)	(331)
Capital Expenditures – Property, Plant and Equipment	16	**(1,576)**	(2,779)	(2,938)
Acquisition	17	**(84)**	-	-
Proceeds From Divestiture of Assets	8	**3,344**	276	258
Current Tax on Divestiture of Assets	8	**(391)**	-	-
Net Change in Investments and Other		**3**	(1,583)	1,486
Net Change in Non-Cash Working Capital		**(270)**	15	6
Cash From (Used in) Investing Activities		**888**	(4,350)	(1,519)
Net Cash Provided (Used) Before Financing Activities		**2,362**	(824)	2,020
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		**(25)**	(18)	(8)
Issuance of U.S. Unsecured Notes	21	**-**	-	814
Repayment of U.S. Unsecured Notes	21	**-**	-	(825)
Common Shares Issued, Net of Issuance Costs	25	**1,449**	-	-
Common Shares Issued Under Stock Option Plans		**-**	28	28
Dividends Paid on Common Shares	11	**(528)**	(805)	(732)
Other		**(2)**	(2)	(3)
Cash From (Used in) Financing Activities		**894**	(797)	(726)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(34)**	52	(2)
Increase (Decrease) in Cash and Cash Equivalents		**3,222**	(1,569)	1,292
Cash and Cash Equivalents, Beginning of Year		**883**	2,452	1,160
Cash and Cash Equivalents, End of Year		**4,105**	883	2,452
Supplementary Cash Flow Information	33			

See accompanying Notes to Consolidated Financial Statements.

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 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.

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

For the years ended December 31,	Oil Sands			Conventional			Refining and Marketing		
	2015	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**3,030**	5,036	3,912	**1,709**	3,225	2,980	**8,805**	12,658	12,706
Less: Royalties	**29**	236	132	**114**	229	204	**-**	-	-
	3,001	4,800	3,780	**1,595**	2,996	2,776	**8,805**	12,658	12,706
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**7,709**	11,767	11,004
Transportation and Blending	**1,815**	2,131	1,749	**230**	346	325	**-**	-	-
Operating	**531**	639	548	**561**	709	701	**754**	703	538
Production and Mineral Taxes	**-**	-	-	**18**	46	35	**-**	-	-
(Gain) Loss on Risk Management	**(404)**	(38)	(37)	**(209)**	(1)	(104)	**(43)**	(27)	19
Operating Cash Flow	**1,059**	2,068	1,520	**995**	1,896	1,819	**385**	215	1,145
Depreciation, Depletion and Amortization	**697**	625	446	**1,148**	1,082	1,170	**191**	156	138
Goodwill Impairment	**-**	-	-	**-**	497	-	**-**	-	-
Exploration Expense	**67**	4	-	**71**	82	114	**-**	-	-
Segment Income (Loss)	**295**	1,439	1,074	**(224)**	235	535	**194**	59	1,007

For the years ended December 31,	Corporate and Eliminations			Consolidated		
	2015	2014	2013	**2015**	2014	2013
Revenues						
Gross Sales	**(337)**	(812)	(605)	**13,207**	20,107	18,993
Less: Royalties	**-**	-	-	**143**	465	336
	(337)	(812)	(605)	**13,064**	19,642	18,657
Expenses						
Purchased Product	**(335)**	(812)	(605)	**7,374**	10,955	10,399
Transportation and Blending	**(2)**	-	-	**2,043**	2,477	2,074
Operating	**(7)**	(6)	(5)	**1,839**	2,045	1,782
Production and Mineral Taxes	**-**	-	-	**18**	46	35
(Gain) Loss on Risk Management	**195**	(596)	415	**(461)**	(662)	293
Depreciation, Depletion and Amortization	**78**	83	79	**2,114**	1,946	1,833
Goodwill Impairment	**-**	-	-	**-**	497	-
Exploration Expense	**-**	-	-	**138**	86	114
Segment Income (Loss)	**(266)**	519	(489)	**(1)**	2,252	2,127
General and Administrative	**335**	379	365	**335**	379	365
Finance Costs	**482**	445	529	**482**	445	529
Interest Income	**(28)**	(33)	(96)	**(28)**	(33)	(96)
Foreign Exchange (Gain) Loss, Net	**1,036**	411	208	**1,036**	411	208
Research Costs	**27**	15	24	**27**	15	24
(Gain) Loss on Divestiture of Assets	**(2,392)**	(156)	1	**(2,392)**	(156)	1
Other (Income) Loss, Net	**2**	(4)	2	**2**	(4)	2
	(538)	1,057	1,033	**(538)**	1,057	1,033
Earnings Before Income Tax				**537**	1,195	1,094
Income Tax Expense (Recovery)				**(81)**	451	432
Net Earnings				**618**	744	662

B) Financial Results by Upstream Product

	Crude Oil [1]								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**3,000**	4,963	3,850	**1,239**	2,456	2,373	**4,239**	7,419	6,223
Less: Royalties	**29**	233	131	**103**	217	196	**132**	450	327
	2,971	4,730	3,719	**1,136**	2,239	2,177	**4,107**	6,969	5,896
Expenses									
Transportation and Blending	**1,814**	2,130	1,748	**213**	326	305	**2,027**	2,456	2,053
Operating	**511**	615	527	**381**	505	489	**892**	1,120	1,016
Production and Mineral Taxes	**-**	-	-	**16**	37	32	**16**	37	32
(Gain) Loss on Risk Management	**(400)**	(38)	(33)	**(157)**	4	(43)	**(557)**	(34)	(76)
Operating Cash Flow	**1,046**	2,023	1,477	**683**	1,367	1,394	**1,729**	3,390	2,871

(1) Includes NGLs.

	Natural Gas								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**22**	67	38	**450**	744	594	**472**	811	632
Less: Royalties	**-**	3	1	**11**	12	8	**11**	15	9
	22	64	37	**439**	732	586	**461**	796	623
Expenses									
Transportation and Blending	**1**	1	1	**17**	20	20	**18**	21	21
Operating	**15**	17	18	**175**	198	208	**190**	215	226
Production and Mineral Taxes	**-**	-	-	**2**	9	3	**2**	9	3
(Gain) Loss on Risk Management	**(4)**	-	(4)	**(52)**	(5)	(61)	**(56)**	(5)	(65)
Operating Cash Flow	**10**	46	22	**297**	510	416	**307**	556	438

	Other								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**8**	6	24	**20**	25	13	**28**	31	37
Less: Royalties	**-**	-	-	**-**	-	-	**-**	-	-
	8	6	24	**20**	25	13	**28**	31	37
Expenses									
Transportation and Blending	**-**	-	-	**-**	-	-	**-**	-	-
Operating	**5**	7	3	**5**	6	4	**10**	13	7
Production and Mineral Taxes	**-**	-	-	**-**	-	-	**-**	-	-
(Gain) Loss on Risk Management	**-**	-	-	**-**	-	-	**-**	-	-
Operating Cash Flow	**3**	(1)	21	**15**	19	9	**18**	18	30

	Total Upstream								
	Oil Sands			Conventional			Total		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Revenues									
Gross Sales	**3,030**	5,036	3,912	**1,709**	3,225	2,980	**4,739**	8,261	6,892
Less: Royalties	**29**	236	132	**114**	229	204	**143**	465	336
	3,001	4,800	3,780	**1,595**	2,996	2,776	**4,596**	7,796	6,556
Expenses									
Transportation and Blending	**1,815**	2,131	1,749	**230**	346	325	**2,045**	2,477	2,074
Operating	**531**	639	548	**561**	709	701	**1,092**	1,348	1,249
Production and Mineral Taxes	**-**	-	-	**18**	46	35	**18**	46	35
(Gain) Loss on Risk Management	**(404)**	(38)	(37)	**(209)**	(1)	(104)	**(613)**	(39)	(141)
Operating Cash Flow	**1,059**	2,068	1,520	**995**	1,896	1,819	**2,054**	3,964	3,339

C) Geographic Information

For the years ended December 31,	Canada 2015	Canada 2014	Canada 2013	United States 2015	United States 2014	United States 2013	Consolidated 2015	Consolidated 2014	Consolidated 2013
Revenues									
Gross Sales	**6,407**	10,604	8,943	**6,800**	9,503	10,050	**13,207**	20,107	18,993
Less: Royalties	**143**	465	336	**-**	-	-	**143**	465	336
	6,264	10,139	8,607	**6,800**	9,503	10,050	**13,064**	19,642	18,657
Expenses									
Purchased Product	**1,607**	2,310	2,022	**5,767**	8,645	8,377	**7,374**	10,955	10,399
Transportation and Blending	**2,043**	2,477	2,074	**-**	-	-	**2,043**	2,477	2,074
Operating	**1,129**	1,367	1,260	**710**	678	522	**1,839**	2,045	1,782
Production and Mineral Taxes	**18**	46	35	**-**	-	-	**18**	46	35
(Gain) Loss on Risk Management	**(435)**	(625)	275	**(26)**	(37)	18	**(461)**	(662)	293
Depreciation, Depletion and Amortization	**1,925**	1,790	1,695	**189**	156	138	**2,114**	1,946	1,833
Goodwill Impairment	**-**	497	-	**-**	-	-	**-**	497	-
Exploration Expense	**138**	86	114	**-**	-	-	**138**	86	114
Segment Income (Loss)	**(161)**	2,191	1,132	**160**	61	995	**(1)**	2,252	2,127

Export Sales

Sales of crude oil, natural gas and NGLs produced or purchased in Canada that have been delivered to customers outside of Canada were $870 million (2014 – $821 million; 2013 – $926 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, natural gas and refined products for the year ended December 31, 2015, Cenovus had three customers (2014 – three; 2013 – three) that individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $4,647 million, $1,705 million and $1,545 million, respectively (2014 – $7,210 million, $2,668 million and $2,316 million; 2013 – $7,032 million, $2,711 million and $1,799 million), which are included in all of the Company's segments.

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

By Segment

As at December 31,	E&E (1) 2015	E&E (1) 2014	PP&E (2) 2015	PP&E (2) 2014	Goodwill 2015	Goodwill 2014	Total Assets 2015	Total Assets 2014
Oil Sands	**1,560**	1,540	**8,907**	8,606	**242**	242	**11,069**	11,024
Conventional	**15**	85	**3,720**	6,038	**-**	-	**3,830**	6,211
Refining and Marketing	**-**	-	**4,398**	3,568	**-**	-	**5,844**	5,520
Corporate and Eliminations	**-**	-	**310**	351	**-**	-	**5,048**	1,940
Consolidated	**1,575**	1,625	**17,335**	18,563	**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 December 31,	E&E 2015	E&E 2014	PP&E 2015	PP&E 2014	Goodwill 2015	Goodwill 2014	Total Assets 2015	Total Assets 2014
Canada	**1,575**	1,625	**13,028**	14,999	**242**	242	**20,627**	20,231
United States	**-**	-	**4,307**	3,564	**-**	-	**5,164**	4,464
Consolidated	**1,575**	1,625	**17,335**	18,563	**242**	242	**25,791**	24,695

E) Capital Expenditures [1]

For the years ended December 31,	**2015**	2014	2013
Capital			
Oil Sands	**1,185**	1,986	1,885
Conventional	**244**	840	1,189
Refining and Marketing	**248**	163	107
Corporate	**37**	62	81
	1,714	3,051	3,262
Acquisition Capital			
Oil Sands	**3**	15	27
Conventional	**1**	3	5
Refining and Marketing	**83**	-	-
	1,801	3,069	3,294

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

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these 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 Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These Consolidated Financial Statements have been prepared in compliance with IFRS.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements of Cenovus were approved by the Board of Directors on February 10, 2016.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has control. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. Substantially all of the Company's Oil Sands and Refining activities are conducted through two joint operations, FCCL Partnership ("FCCL") and WRB Refining LP ("WRB"), and accordingly, the accounts reflect the Company's share of the assets, liabilities, revenues and expenses.

B) Foreign Currency Translation

Functional and Presentation Currency

The Company's presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period-end exchange rates for assets and liabilities, and using average rates over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income ("OCI") as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation that continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

Transactions and Balances

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period-end date. Any gains or losses are recorded in the Consolidated Statements of Earnings.

C) Revenue Recognition

Revenues associated with the sales of Cenovus's crude oil, natural gas, NGLs, and petroleum and refined products are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer. Revenues from crude oil and natural gas production represent the Company's share, net of royalty payments to governments and other mineral interest owners.

Revenue from fee-for-service hydrocarbon trans-loading services is recognized in the period the service is provided.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided as agent are recorded as the services are provided.

D) Transportation and Blending

The costs associated with the transportation of crude oil, natural gas and NGLs, including the cost of diluent used in blending, are recognized when the product is sold.

E) Exploration Expense

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Costs incurred after the legal right to explore is obtained, are initially capitalized. If it is determined that the field/project/area is not technically feasible and commercially viable or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

F) Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component and an other post-employment benefit plan ("OPEB").

Pension expense for the defined contribution pension is recorded as the benefits are earned.

The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The amount recognized in other liabilities on the Consolidated Balance Sheets for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets. Any surplus resulting from this calculation is limited to the present value of any economic benefits available in the form of refunds from the plans or reductions in future contributions to the plans.

Changes in the defined benefit obligation from service costs, net interest and remeasurements are recognized as follows:

- Service costs, including current service costs, past service costs, gains and losses on curtailments, and settlements, are recorded with pension benefit costs.
- Net interest is calculated by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability measured. Interest expense and interest income on net post-employment benefit liabilities and assets are recorded with pension benefit costs in operating, and general and administrative expenses, as well as PP&E and E&E assets.
- Remeasurements, composed of actuarial gains and losses, the effect of changes to the asset ceiling (excluding interest) and the return on plan assets (excluding interest income), are charged or credited to equity in OCI in the period in which they arise. Remeasurements are not reclassified to net earnings in subsequent periods.

Pension benefit costs are recorded in operating, and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the associated salaries of the employees rendering the service are recorded.

G) Income Taxes

Income taxes comprise current and deferred taxes. Income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is provided on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future or when distributions can be made without incurring income taxes.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized. Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

H) Net Earnings per Share Amounts

Basic net earnings per share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

I) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less.

J) Inventories

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

K) Exploration and Evaluation Assets

Costs incurred after the legal right to explore an area has been obtained, and before technical feasibility and commercial viability of the field/project/area have been established, are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired. E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources.

Once technical feasibility and commercial viability have been established, the carrying value of the E&E asset is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

L) Property, Plant and Equipment

General

PP&E is stated at cost less accumulated depreciation, depletion and amortization ("DD&A"), and net impairment losses. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of PP&E are recognized in net earnings.

Development and Production Assets

Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of the crude oil and natural gas properties, as well as any E&E expenditures incurred in finding reserves of crude oil or natural gas transferred from E&E assets. Capitalized costs include directly attributable internal costs, decommissioning liabilities and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

Costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using forward prices and costs. For the purpose of this calculation, natural gas is converted to crude oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up, can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Other Upstream Assets

Other upstream assets include pipelines and information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three to 35 years.

Refining Assets

The initial acquisition costs of refining PP&E are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs.

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

Land Improvements and Buildings	25 to 40 years
Office Equipment and Vehicles	3 to 20 years
Refining Equipment	5 to 35 years

The residual value, method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

Other Assets

Costs associated with the crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 40 years.

The residual value, method of amortization and the useful lives of the assets are reviewed annually and adjusted on a prospective basis, if appropriate.

M) Impairment

Non-Financial Assets

PP&E and E&E assets are reviewed separately for indicators of impairment quarterly or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

If indicators of impairment exist, the recoverable amount of the cash-generating unit ("CGU") is estimated as the greater of value-in-use ("VIU") and fair value less costs of disposal ("FVLCOD"). VIU is estimated as the discounted present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is determined by estimating the discounted after-tax future net cash flows. For Cenovus's upstream assets, FVLCOD is based on the discounted after-tax cash flows of reserves and resources using forward prices and costs, consistent with Cenovus's independent qualified reserves evaluators, and may consider an evaluation of comparable asset transactions.

If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Goodwill is allocated to the CGUs to which it contributes to the future cash flows.

Impairment losses on PP&E and E&E assets are recognized in the Consolidated Statements of Earnings as additional DD&A and exploration expense, respectively.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

Financial Assets

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment, the loss event has an impact on future cash flows and the loss can be reliably estimated.

Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. For equity securities, a significant or prolonged decline in the fair value of the security below cost is evidence that the assets are impaired.

An impairment loss on a financial asset carried at amortized cost is calculated as the difference between the amortized cost and the present value of the future cash flows discounted at the asset's original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. Impairment losses on financial assets carried at amortized cost are reversed through net earnings in subsequent periods if the amount of the loss decreases.

N) Leases

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases within PP&E.

O) Business Combinations and Goodwill

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

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

P) Provisions

General

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings.

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, crude oil and natural gas processing facilities, refining facilities and the crude-by-rail terminal. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in PP&E is depreciated over the useful life of the related asset.

Actual expenditures incurred are charged against the accumulated liability.

Q) Share Capital

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income taxes.

R) Stock-Based Compensation

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), stock options with associated tandem stock appreciation rights ("TSARs"), performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). Stock-based compensation costs are recorded in general and administrative expense, or E&E and PP&E when directly related to exploration or development activities.

Net Settlement Rights

NSRs are accounted for as equity instruments, which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as stock-based compensation costs over the vesting period, with a corresponding increase recorded as paid in surplus in Shareholders' Equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Tandem Stock Appreciation Rights

TSARs are accounted for as liability instruments, which are measured at fair value at each period end using the Black-Scholes-Merton valuation model. The fair value is recognized as stock-based compensation costs over the vesting period. When options are settled for cash, the liability is reduced by the cash settlement paid. When options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the option are recorded as share capital.

Performance, Restricted and Deferred Share Units

PSUs, RSUs and DSUs 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 stock-based compensation costs over the vesting period. Fluctuations in the fair values are recognized as stock-based compensation costs in the period they occur.

S) Financial Instruments

The Company's financial assets include cash and cash equivalents, accounts receivable and accrued revenues, risk management assets, available for sale financial assets and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, risk management liabilities, short-term borrowings and long-term debt.

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership. A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, this exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the carrying amounts of the liabilities is recognized in the Consolidated Statements of Earnings.

Financial instruments are classified as either "fair value through profit and loss", "loans and receivables", "held-to-maturity investments", "available for sale financial assets" or "financial liabilities measured at amortized cost". The Company determines the classification of its financial assets at initial recognition. Financial instruments are initially measured at fair value except in the case of "financial liabilities measured at amortized cost", which are initially measured at fair value net of directly attributable transaction costs.

As required by IFRS, the Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Fair Value through Profit or Loss

Financial assets and financial liabilities at "fair value through profit or loss" are either "held-for-trading" or have been "designated at fair value through profit or loss". In both cases, the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated

Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a (gain) loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

Derivative financial instruments are used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Derivative financial instruments are not used for speculative purposes. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Loans and Receivables

"Loans and receivables" are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. "Loans and receivables" comprise cash and cash equivalents, accounts receivable and accrued revenues, and long-term receivables. Gains and losses on "loans and receivables" are recognized in net earnings when the "loans and receivables" are derecognized or impaired.

Available for Sale Financial Assets

"Available for sale financial assets" are measured at fair value, with changes in the fair value recognized in OCI. When an active market is non-existent, fair value is determined using valuation techniques. When fair value cannot be reliably measured, such assets are carried at cost. Available for sale financial assets comprise investments in the equity of private companies that the Company does not control or have significant influence over.

Financial Liabilities Measured at Amortized Cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt or as a prepayment and amortized using the effective interest method.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2015. Employee stock-based compensation costs previously included in operating expense have been reclassified to general and administrative expense. As a result, for the years ended December 31, 2014 and 2013, expenses of $21 million and $16 million, respectively, were reclassified.

U) Recent Accounting Pronouncements

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.

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2016 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2015. The standards applicable to the Company are as follows and will be adopted on their respective effective dates:

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.

Financial Instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39").

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. For financial liabilities, IFRS 9 retains most of the IAS 39 requirements; however, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. In addition, a new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. IFRS 9 also includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Cenovus does not currently apply hedge accounting.

IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions, and use judgment regarding the reported amounts of assets and liabilities, and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in the Company's Consolidated Financial Statements.

Joint Arrangements

Cenovus holds a 50 percent ownership interest in two jointly controlled entities, FCCL and WRB. The classification of these joint arrangements as either a joint operation or a joint venture requires judgment. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of FCCL and WRB.

As a result, these joint arrangements are classified as joint operations and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, "*Joint Arrangements"*, the Company considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnership. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third-party borrowings.

- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of CGUs

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretations. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses.

B) Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Conventional segments. The Company's crude oil and natural gas reserves are evaluated annually and reported to the Company by independent qualified reserves evaluators.

Impairment of Assets

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses, and income tax rates. Recoverable amounts for the Company's refining assets and crude-by-rail terminal use assumptions such as throughput, forward commodity prices, operating expenses, transportation capacity, supply and demand conditions and income tax rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream crude oil and natural gas assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgement to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In

addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

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

5. FINANCE COSTS

For the years ended December 31,	**2015**	2014	2013
Interest Expense – Short-Term Borrowings and Long-Term Debt	**328**	285	271
Premium on Redemption of Long-Term Debt	**-**	-	33
Unwinding of Discount on Decommissioning Liabilities (Note 22)	**126**	120	97
Other	**28**	18	30
Interest Expense – Partnership Contribution Payable [1]	**-**	22	98
	482	445	529

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

6. INTEREST INCOME

For the years ended December 31,	**2015**	2014	2013
Interest Income – Partnership Contribution Receivable [1]	**-**	-	(82)
Other	**(28)**	(33)	(14)
	(28)	(33)	(96)

(1) In 2013, Cenovus received the remaining principal and accrued interest due under the Partnership Contribution Receivable.

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2015**	2014	2013
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued From Canada	**1,064**	458	357
U.S. Dollar Partnership Contribution Receivable Issued From Canada	**-**	-	(305)
Other	**33**	(47)	(12)
Unrealized Foreign Exchange (Gain) Loss	**1,097**	411	40
Realized Foreign Exchange (Gain) Loss	**(61)**	-	168
	1,036	411	208

8. 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 2014, the Company completed the sale of certain Wainwright properties to an unrelated third party for net proceeds of $234 million, resulting in a gain of $137 million. The Company also completed the sale of certain Bakken properties to an unrelated third party for net proceeds of $35 million, resulting in a gain of $16 million. Other divestitures in 2014 included the sale of certain non-core properties, resulting in a gain of $4 million. These assets and results of operations were reported in the Conventional segment.

In 2013, the Company completed the sale of the Lower Shaunavon asset to an unrelated third party for net proceeds of $241 million, resulting in a loss of $2 million. These assets and results of operations were reported in the Conventional segment. Other divestitures in 2013 included undeveloped land in northern Alberta, cancellation of some of the Company's non-core Oil Sands mineral rights under the Lower Athabasca Regional Plan and a third-party land exchange.

9. IMPAIRMENTS

A) Cash-Generating Unit 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.

2013 Impairments

There were no CGU impairments for the year ended December 31, 2013.

B) Asset Impairments

Exploration and Evaluation Assets

In 2015, $138 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 $71 million within the Oil Sands and Conventional segments, respectively.

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.

In 2013, $50 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.

Property, Plant and Equipment, Net

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

For the years ended December 31,	**2015**	2014	2013
Development and Production (Note 16)	**16**	65	59
	16	65	59

In 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.

In 2013, the Company impaired its Lower Shaunavon asset for $57 million prior to its divestiture. The impairment was recorded in the Conventional segment.

10. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	**2015**	2014	2013
Current Tax			
Canada	**586**	94	143
United States	**(12)**	(2)	45
Total Current Tax Expense (Recovery)	**574**	92	188
Deferred Tax Expense (Recovery)	**(655)**	359	244
	(81)	451	432

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 and 38.5 percent in 2013.

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

For the years ended December 31,	**2015**	2014	2013
Earnings Before Income Tax	**537**	1,195	1,094
Canadian Statutory Rate	**26.1%**	25.2%	25.2%
Expected Income Tax	**140**	301	276
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(41)**	(43)	87
Non-Deductible Stock-Based Compensation	**7**	13	10
Non-Taxable Capital Losses	**137**	74	6
Unrecognized Capital Losses Arising From Unrealized Foreign Exchange	**135**	50	25
Adjustments Arising From Prior Year Tax Filings	**(55)**	(16)	(13)
Derecognition (Recognition) of Capital Losses	**(149)**	(9)	15
Recognition of U.S. Tax Basis	**(415)**	-	-
Change in Statutory Rate	**161**	-	-
Foreign Exchange Gains (Losses) not Included in Net Earnings	**-**	(13)	19
Goodwill Impairment	**-**	125	-
Other	**(1)**	(31)	7
Total Tax	**(81)**	451	432
Effective Tax Rate	**(15.1)%**	37.7%	39.5%

The analysis of deferred income tax liabilities and deferred income tax assets is:

As at December 31,	**2015**	2014
Net Deferred Income Tax Liabilities		
Deferred Tax Liabilities to be Settled Within 12 Months	**58**	296
Deferred Tax Liabilities to be Settled After More Than 12 Months	**2,758**	3,006
	2,816	3,302

For the purposes of the preceding table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where they occur in the same entity and jurisdiction. The deferred income tax liabilities to be settled within 12 months represents Management's estimate of the timing of the reversal of temporary differences and may not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is:

Deferred Income Tax Liabilities	Property, Plant and Equipment	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2013	3,000	88	2	152	3,242
Charged/(Credited) to Earnings	22	79	119	(111)	109
Charged/(Credited) to OCI	84	-	-	-	84
As at December 31, 2014	3,106	167	121	41	3,435
Charged/(Credited) to Earnings	(246)	(167)	(39)	(24)	(476)
Charged/(Credited) to OCI	192	-	-	-	192
As at December 31, 2015	**3,052**	**-**	**82**	**17**	**3,151**

Deferred Income Tax Assets	Unused Tax Losses	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2013	(104)	-	(35)	(241)	(380)
Charged/(Credited) to Earnings	41	-	31	178	250
Charged/(Credited) to OCI	(9)	-	-	6	(3)
As at December 31, 2014	(72)	-	(4)	(57)	(133)
Charged/(Credited) to Earnings	(80)	(36)	(4)	(59)	(179)
Charged/(Credited) to OCI	(20)	-	-	(3)	(23)
As at December 31, 2015	**(172)**	**(36)**	**(8)**	**(119)**	**(335)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at December 31, 2013	2,862
Charged/(Credited) to Earnings	359
Charged/(Credited) to OCI	81
Net Deferred Income Tax Liabilities as at December 31, 2014	3,302
Charged/(Credited) to Earnings	(655)
Charged/(Credited) to OCI	169
Net Deferred Income Tax Liabilities as at December 31, 2015	**2,816**

No deferred tax liability has been recognized as at December 31, 2015 on temporary differences associated with investments in subsidiaries and joint arrangements where the Company can control the timing of the reversal of the temporary difference and the reversal is not probable in the foreseeable future. As at December 31, 2015, the Company had temporary differences of $6,692 million (2014 – $6,667 million) in respect of certain of these investments where, on dissolution or sale, a tax liability may exist.

The approximate amounts of tax pools available are:

As at December 31,	2015	2014
Canada	**4,882**	6,153
United States	**2,119**	958
	7,001	7,111

As at December 31, 2015, the above tax pools included $13 million (2014 – $8 million) of Canadian non-capital losses and $380 million (2014 – $140 million) of U.S. federal net operating losses. These losses expire no earlier than 2031.

Also included in the December 31, 2015 tax pools are Canadian net capital losses totaling $44 million (2014 – $593 million), which are available for carry forward to reduce future capital gains. Of these losses, $41 million are unrecognized as a deferred income tax asset as at December 31, 2015 (2014 – $559 million). Recognition is dependent on future capital gains. The Company has not recognized $828 million of net capital losses associated with unrealized foreign exchange losses on its U.S. denominated debt.

11. PER SHARE AMOUNTS

A) Net Earnings Per Share

For the years ended December 31,	**2015**	2014	2013
Net Earnings – Basic and Diluted ($ millions)	**618**	744	662
Basic – Weighted Average Number of Shares (millions)	**818.7**	756.9	755.9
Dilutive Effect of Cenovus TSARs	**-**	0.7	1.6
Dilutive Effect of Cenovus NSRs	**-**	-	-
Diluted – Weighted Average Number of Shares	**818.7**	757.6	757.5
Net Earnings Per Share ($)			
Basic	**$0.75**	$0.98	$0.88
Diluted	**$0.75**	$0.98	$0.87

B) Dividends Per Share

For the year ended December 31, 2015, the Company paid dividends of $710 million or $0.8524 per share (2014 – $805 million, $1.0648 per share; 2013 – $732 million, $0.968 per share), including cash dividends of $528 million. For 2014 and 2013, all dividends were 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.

12. CASH AND CASH EQUIVALENTS

As at December 31,	**2015**	2014
Cash	**323**	458
Short-Term Investments	**3,782**	425
	4,105	883

13. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	**2015**	2014
Accruals	**1,037**	1,417
Partner Advances	**35**	44
Prepaids and Deposits	**71**	56
Trade	**61**	6
Joint Operations Receivables	**13**	18
Other	**34**	41
	1,251	1,582

14. INVENTORIES

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

During the year ended December 31, 2015, approximately $10,618 million of produced and purchased inventory was recorded as an expense (2014 – $15,065 million; 2013 – $13,895 million).

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 (2014 – $131 million).

15. EXPLORATION AND EVALUATION ASSETS

COST	
As at December 31, 2013	1,473
Additions	279
Transfers to PP&E (Note 16)	(53)
Exploration Expense (Note 9)	(86)
Divestitures	(2)
Change in Decommissioning Liabilities	14
As at December 31, 2014	1,625
Additions	138
Acquisitions	3
Transfers to PP&E (Note 16)	(49)
Exploration Expense (Note 9)	(138)
Change in Decommissioning Liabilities	(4)
As at December 31, 2015	**1,575**

16. 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 15)	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 17)	1	-	-	83	84
Transfers From E&E Assets (Note 15)	49	-	-	-	49
Change in Decommissioning Liabilities	(635)	-	1	(1)	(635)
Exchange Rate Movements and Other	(1)	-	814	-	813
Divestitures (Note 8)	(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 9)	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 9)	200	-	-	-	200
Exchange Rate Movements and Other	(1)	-	123	1	123
Divestitures (Note 8)	(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 DD&A:

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

17. 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.

18. OTHER ASSETS

As at December 31,	**2015**	2014
Investments	**46**	36
Long-Term Receivables	**1**	7
Prepaids	**7**	7
Other	**22**	20
	76	70

19. GOODWILL

As at December 31,	**2015**	2014
Carrying Value, Beginning of Year	**242**	739
Impairment Losses (Note 9)	**-**	(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.

20. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	**2015**	2014
Accruals	**1,366**	2,057
Partner Advances	**35**	218
Trade	**68**	51
Employee Long-Term Incentives	**47**	91
Interest	**73**	61
Other	**113**	110
	1,702	2,588

21. LONG-TERM DEBT

As at December 31,		2015	2014
Revolving Term Debt [1]	A	-	-
U.S. Dollar Denominated Unsecured Notes	B	6,574	5,510
Total Debt Principal	C	6,574	5,510
Debt Discounts and Transaction Costs	D	(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.

The weighted average interest rate on outstanding debt for the year ended December 31, 2015 was 5.3 percent (2014 – 5.0 percent).

A) Revolving Term Debt

As at December 31, 2015, Cenovus had in place a committed credit facility in the amount of $4.0 billion or the equivalent amount in U.S. dollars. 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. The maturity dates are extendable from time to time, at the option of Cenovus and upon agreement from the lenders. Borrowings are available by way of Bankers' Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. As at December 31, 2015, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2014 – $nil).

B) Unsecured Notes

Unsecured notes are composed of:

As at December 31,	US$ Principal Amount	2015	2014
5.70% due October 15, 2019	1,300	1,799	1,508
3.00% due August 15, 2022	500	692	580
3.80% due September 15, 2023	450	623	522
6.75% due November 15, 2039	1,400	1,938	1,624
4.45% due September 15, 2042	750	1,038	870
5.20% due September 15, 2043	350	484	406
		6,574	5,510

On June 24, 2014, Cenovus filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2015, no notes have been issued under this U.S. base shelf prospectus. The U.S. base shelf prospectus expires in July 2016.

On June 25, 2014, Cenovus filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2015, no medium term notes have been issued under this Canadian base shelf prospectus. The Canadian base shelf prospectus expires in July 2016.

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

C) Mandatory Debt Payments

	US$ Principal Amount	C$ Principal Amount	**Total C$ Equivalent**
2016	-	-	-
2017	-	-	-
2018	-	-	-
2019	1,300	-	**1,799**
2020	-	-	-
Thereafter	3,450	-	**4,775**
	4,750	-	**6,574**

D) Debt Discounts and Transaction Costs

Long-term debt transaction costs and discounts associated with the unsecured notes are recorded within long-term debt and are amortized using the effective interest rate method. Transaction costs associated with the revolving term debt are recorded as a prepayment and are amortized over the remaining term of the committed credit facility. During 2015, additional transaction costs of $3 million were recorded (2014 – $2 million).

22. 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**	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 is $6,665 million (December 31, 2014 – $8,333 million), which has been discounted using a credit-adjusted risk-free rate of 6.4 percent (December 31, 2014 – 4.9 percent). An inflation rate of two percent (2014 – two percent) was used to calculate the decommissioning provision. Most of these obligations are not expected to be paid for several years, or decades, and are expected to be funded from general resources at that time. The Company expects to settle approximately $35 million to $70 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from lower cost estimates, partially offset by accelerated timing of decommissioning liabilities over the estimated life of the reserves.

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	2015		2014	
As at December 31,	**Credit-Adjusted Risk-Free Rate**	**Inflation Rate**	Credit-Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	**(247)**	**319**	(419)	574
One Percent Decrease	**308**	**(259)**	562	(433)

23. OTHER LIABILITIES

As at December 31,	**2015**	2014
Employee Long-Term Incentives	**40**	57
Pension and OPEB (Note 24)	**66**	84
Other	**36**	31
	142	172

24. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and OPEB. Most of the employees participate in the defined contribution pension. Starting in 2012, employees who meet certain criteria may move from the current defined contribution component to a defined benefit component for their future service.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The Company's OPEB provides certain retired employees with health care and dental benefits until age 65 and life insurance benefits.

The Company is required to file an actuarial valuation of its registered defined benefit pension with the provincial regulator at least every three years. The most recently filed valuation was dated December 31, 2014 and the next required actuarial valuation will be as at December 31, 2017.

A) Defined Benefit and OPEB Plan Obligation and Funded Status

Information related to defined benefit pension and OPEB plans, based on actuarial estimations, is:

	Pension Benefits		OPEB	
As at December 31,	**2015**	2014	**2015**	2014
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**200**	148	**23**	18
Current Service Costs	**19**	15	**3**	2
Interest Costs [1]	**8**	7	**1**	1
Benefits Paid	**(6)**	(3)	**(1)**	-
Plan Participant Contributions	**3**	3	**-**	-
Past Service Costs – Curtailments	**(5)**	-	**-**	-
Settlements	**(20)**	-	**-**	-
Remeasurements:				
(Gains) Losses from Experience Adjustments	**(3)**	-	**-**	-
(Gains) Losses from Changes in Demographic Assumptions	**-**	(1)	**-**	-
(Gains) Losses from Changes in Financial Assumptions	**(28)**	31	**-**	2
Defined Benefit Obligation, End of Year	**168**	200	**26**	23
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**139**	115	**-**	-
Employer Contributions	**16**	12	**-**	-
Plan Participant Contributions	**3**	3	**-**	-
Benefits Paid	**(6)**	(3)	**-**	-
Settlements	**(23)**	-	**-**	-
Interest Income [1]	**2**	4	**-**	-
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	**(3)**	8	**-**	-
Fair Value of Plan Assets, End of Year	**128**	139	**-**	-
Pension and Other Post-Employment Benefit (Liability) [2]	**(40)**	(61)	**(26)**	(23)

(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.
(2) Pension and OPEB liabilities are included in other liabilities on the Consolidated Balance Sheets.

The weighted average duration of the defined benefit pension and OPEB obligations are 15 years and 12 years, respectively.

B) Pension and OPEB Costs

For the years ended December 31,	Pension Benefits 2015	2014	2013	OPEB 2015	2014	2013
Defined Benefit Plan Cost						
Current Service Costs	**19**	15	17	**3**	2	2
Past Service Costs – Curtailments	**(5)**	-	-	**-**	-	-
Net Settlement Costs	**3**	-	-	**-**	-	-
Net Interest Costs	**6**	3	4	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**3**	(8)	(7)	**-**	-	-
(Gains) Losses from Experience Adjustments	**(3)**	-	1	**-**	-	-
(Gains) Losses from Changes in Demographic Assumptions	**-**	(1)	12	**-**	-	(1)
(Gains) Losses from Changes in Financial Assumptions	**(28)**	31	(19)	**-**	2	(4)
Defined Benefit Plan Cost (Gain)	**(5)**	40	8	**4**	5	(2)
Defined Contribution Plan Cost	**29**	30	27	**-**	-	-
Total Plan Cost	**24**	70	35	**4**	5	(2)

C) Investment Objectives and Fair Value of Plan Assets

The objective of the asset allocation is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The allocation of assets between the various types of investment funds is monitored monthly and is re-balanced as necessary. The asset allocation structure targets an investment of 60 to 70 percent in equity securities, 30 percent in debt instruments and the remainder invested in real estate and other.

The Company does not use derivative instruments to manage the risks of its plan assets. There has been no change in the process used by the Company to manage these risks from prior periods.

The fair value of the plan assets is:

As at December 31,	2015	2014
Equity Securities		
Equity Funds and Balanced Funds	**73**	75
Other	**3**	9
Bond Funds	**31**	36
Non-Invested Assets	**17**	15
Real Estate	**4**	4
	128	139

Fair value of equity securities and bond funds are based on the trading price of the underlying funds. The fair value of the non-invested assets is the discounted value of the expected future payments. The fair value of real estate is determined by accredited real estate appraisers.

Equity securities do not include any direct investments in Cenovus shares.

D) Funding

The defined benefit pension is funded in accordance with federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plan are based on the most recent actuarial valuation as at December 31, 2014, and direction by the Management Pension Committee and Human Resources and Compensation Committee of the Board of Directors.

Employees participating in the defined benefit pension are required to contribute four percent of their pensionable earnings, up to an annual maximum, and the Company provides the balance of the funding necessary to ensure benefits will be fully provided for at retirement. The expected employer contributions for the year ended December 31, 2016 are $15 million for the defined benefit pension plan and $nil for the OPEB. The OPEB is funded on an as required basis.

E) Actuarial Assumptions and Sensitivities

Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

	Pension Benefits			OPEB		
For the years ended December 31,	**2015**	2014	2013	**2015**	2014	2013
Discount Rate	**4.00%**	3.75%	4.75%	**3.75%**	3.75%	4.75%
Future Salary Growth Rate	**3.80%**	4.32%	4.39%	**5.15%**	5.65%	5.65%
Average Longevity (Years)	**88.3**	88.3	88.5	**88.3**	88.3	88.5
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**7.00%**	7.00%	7.00%

The discount rates are determined with reference to market yields on high quality corporate debt instruments of similar duration to the benefit obligations at the end of the reporting period.

Sensitivities

The sensitivity of the defined benefit and OPEB obligation to changes in relevant actuarial assumptions is shown below.

	2015		2014	
As at December 31,	**One Percentage Point Increase**	**One Percentage Point Decrease**	One Percentage Point Increase	One Percentage Point Decrease
Discount Rate	**(27)**	**35**	(34)	43
Future Salary Growth Rate	**3**	**(3)**	4	(4)
Health Care Cost Trend Rate	**2**	**(2)**	2	(2)
Future Mortality Rate (Years)	**4**	**(4)**	4	(4)

The above sensitivity analysis is based on a change in an assumption while holding all other assumptions constant; however, the changes in some assumptions may be correlated. The same methodologies have been used to calculate the sensitivity of the defined benefit obligation to significant actuarial assumptions as have been applied when calculating the defined benefit pension liability recorded on the Consolidated Balance Sheets.

F) Risks

Through its defined benefit pension and OPEB plans, the Company is exposed to actuarial risks, such as longevity risk, interest rate risk, investment risk and salary risk.

Longevity Risk

The present value of the defined benefit plan obligation is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of participants will increase the defined benefit plan obligation.

Interest Rate Risk

A decrease in corporate bond yields will increase the defined benefit plan obligation, although this will be partially offset by an increase in the return on debt holdings.

Investment Risk

The present value of the defined benefit plan obligation is calculated using a discount rate determined by reference to high quality corporate bond yields. If the return on plan assets is below this rate, a plan deficit will result. Due to the long-term nature of the plan liabilities, a higher portion of the plan assets are invested in equity securities than in debt instruments and real estate.

Salary Risk

The present value of the defined benefit plan obligation is calculated by reference to the future salaries of plan participants. As such, an increase in the salary of the plan participants will increase the defined benefit obligation.

25. 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

	2015		2014	
As at December 31,	**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. Share issuance costs of $53 million were incurred.

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 (2014 – nil).

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

C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana Corporation ("Encana") under the plan of arrangement into two independent energy companies, Encana and Cenovus. In addition, paid in surplus includes stock-based compensation expense related to the Company's NSRs discussed in Note 27A).

	Pre-Arrangement Earnings	**Stock-Based Compensation**	**Total**
As at December 31, 2013	4,086	133	4,219
Stock-Based Compensation Expense	-	72	72
As at December 31, 2014	4,086	205	4,291
Stock-Based Compensation Expense	-	39	39
As at December 31, 2015	**4,086**	**244**	**4,330**

26. 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**

27. 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. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options expire after seven years.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated tandem stock appreciation rights. In lieu of exercising the options, the tandem stock appreciation rights give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company on or after February 24, 2011 have associated net settlement rights. The net settlement rights, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The tandem stock appreciation rights and net settlement rights vest and expire under the same terms and conditions as the underlying options. For the purpose of this financial statement note, options with associated tandem stock appreciation rights are referred to as "TSARs" and options with associated net settlement rights are referred to as "NSRs".

In addition, certain of the TSARs are performance based ("performance TSARs"). All performance TSARs have vested, and, as such, terms and conditions are consistent with TSARs, which were not performance based.

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 with weighted average assumptions as follows:

Risk-Free Interest Rate	**0.75%**
Expected Dividend Yield	**3.60%**
Expected Volatility [1]	**28.27%**
Expected Life (Years)	**4.55**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The following tables summarize 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**

As at December 31, 2015	**Outstanding NSRs**		
Range of Exercise Price ($)	**Number of NSRs** (Thousands)	**Weighted Average Remaining Contractual Life** (Years)	**Weighted Average Exercise Price** ($)
15.00 to 19.99	**6**	**6.68**	**18.07**
20.00 to 24.99	**4,075**	**6.15**	**22.26**
25.00 to 29.99	**14,281**	**5.14**	**28.39**
30.00 to 34.99	**12,642**	**4.18**	**32.61**
35.00 to 39.99	**11,110**	**2.79**	**38.19**
	42,114	**4.33**	**31.65**

As at December 31, 2015 Range of Exercise Price ($)	Exercisable NSRs Number of NSRs (Thousands)	Weighted Average Exercise Price ($)
15.00 to 19.99	-	-
20.00 to 24.99	40	22.99
25.00 to 29.99	4,404	28.41
30.00 to 34.99	7,930	32.64
35.00 to 39.99	11,110	38.19
	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. Fair value was estimated at the period-end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	0.75%
Expected Dividend Yield	4.14%
Expected Volatility [1]	29.24%
Cenovus's Common Share Price	$17.50

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees as at December 31, 2015 was $nil (December 31, 2014 – $nil).

The following tables summarize 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

As at December 31, 2015 Range of Exercise Price ($)	Outstanding and Exercisable TSARs Number of TSARs (Thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	3,497	1.16	26.46
30.00 to 39.99	148	1.98	32.88
	3,645	1.20	26.72

The closing price of Cenovus's common shares on the TSX as at December 31, 2015 was $17.50.

B) Performance Share Units

Cenovus has granted PSUs to certain employees under its Performance Share Unit Plan for Employees. PSUs 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. For a portion of PSUs, the number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $49 million as at December 31, 2015 (2014 – $109 million) in the Consolidated Balance Sheets for 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 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 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 stock-based compensation costs over the vesting period. Fluctuations in the fair value are recognized as stock-based compensation costs in the period they occur.

The Company has recorded a liability of $11 million as at December 31, 2015 (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 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

Under two Deferred Share Unit Plans, Cenovus directors, officers and employees may receive DSUs, which are equivalent in value to a common share of the Company. Employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $26 million as at December 31, 2015 (2014 – $31 million) in the Consolidated Balance Sheets for 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

For the years ended December 31,	**2015**	2014	2013
NSRs	**27**	41	35
TSARs	**(5)**	(10)	(16)
PSUs	**(13)**	34	32
RSUs	**6**	-	-
DSUs	**(5)**	(5)	-
Stock-Based Compensation Expense (Recovery)	**10**	60	51
Stock-Based Compensation Costs Capitalized	**6**	29	18
Total Stock-Based Compensation	**16**	89	69

28. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2015**	2014	2013
Salaries, Bonuses and Other Short-Term Employee Benefits	**534**	550	494
Defined Contribution Pension Plan	**19**	18	17
Defined Benefit Pension Plan and OPEB	**17**	14	15
Stock-Based Compensation Expense (Note 27)	**10**	60	51
Termination Benefits	**43**	-	-
	623	642	577

29. RELATED PARTY TRANSACTIONS

Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is:

For the years ended December 31,	**2015**	2014	2013
Salaries, Director Fees and Short-Term Benefits	**30**	29	31
Post-Employment Benefits	**5**	4	4
Stock-Based Compensation	**5**	20	24
	40	53	59

Post-employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs recorded during the year associated with stock options, NSRs, TSARs, PSUs, RSUs and DSUs.

30. 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, current and long-term portions of long-term debt, and the current and long-term portions of the Partnership Contribution Payable, 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**	2014	2013
Debt	**6,525**	5,458	4,997
Add (Deduct):			
Cash and Cash Equivalents	**(4,105)**	(883)	(2,452)
Current Portion of Partnership Contribution Payable [1]	**-**	-	438
Partnership Contribution Payable [1]	**-**	-	1,087
Net Debt	**2,420**	4,575	4,070
Debt	**6,525**	5,458	4,997
Shareholders' Equity	**12,391**	10,186	9,946
	18,916	15,644	14,943
Debt to Capitalization	**34%**	35%	33%
Net Debt	**2,420**	4,575	4,070
Shareholders' Equity	**12,391**	10,186	9,946
	14,811	14,761	14,016
Net Debt to Capitalization	**16%**	31%	29%

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

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

As at December 31,	**2015**	2014	2013
Debt	**6,525**	5,458	4,997
Net Debt	**2,420**	4,575	4,070
Net Earnings	**618**	744	662
Add (Deduct):			
Finance Costs	**482**	445	529
Interest Income	**(28)**	(33)	(96)
Income Tax Expense (Recovery)	**(81)**	451	432
Depreciation, Depletion and Amortization	**2,114**	1,946	1,833
Goodwill Impairment	**-**	497	-
E&E Impairment	**138**	86	50
Unrealized (Gain) Loss on Risk Management	**195**	(596)	415
Foreign Exchange (Gain) Loss, Net	**1,036**	411	208
(Gain) Loss on Divestitures of Assets	**(2,392)**	(156)	1
Other (Income) Loss, Net	**2**	(4)	2
Adjusted EBITDA	**2,084**	3,791	4,036
Debt to Adjusted EBITDA	**3.1x**	1.4x	1.2x
Net Debt to Adjusted EBITDA	**1.2x**	1.2x	1.0x

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.

31. 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 (2014 carrying value – $5,458 million, fair value – $5,726 million).

Available for sale financial 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**	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

	2015			2014		
	Risk Management			Risk Management		
As at December 31,	**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**	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:

As at 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 power contracts (2014 - $4 million gain).
(2) Includes a decrease of $14 million related to power contracts (2014 - $10 million decrease).

Financial assets and liabilities are only offset if Cenovus has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Cenovus offsets risk management assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. No additional unrealized risk management positions are subject to an enforceable master netting arrangement or similar agreement that are not otherwise offset.

The following table provides a summary of the Company's offsetting risk management positions:

	2015			2014		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**317**	**46**	**271**	479	17	462
Amount Offset	**(16)**	**(16)**	**-**	(1)	(1)	-
Net Amount per Consolidated Financial Statements	**301**	**30**	**271**	478	16	462

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. Additional cash collateral is required if, on a net basis, risk management payables exceed risk management receivables on a particular day. As at December 31, 2015, $26 million (2014 – $12 million) was pledged as collateral, of which $5 million (2014 – $7 million) could have been withdrawn.

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

For the years ended December 31,	**2015**	2014	2013
Realized (Gain) Loss [1]	**(656)**	(66)	(122)
Unrealized (Gain) Loss [2]	**195**	(596)	415
(Gain) Loss on Risk Management	**(461)**	(662)	293

(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.

32. 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) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of forward commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments.

The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy is not to use derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps and costless collars to partially mitigate its exposure to the commodity price risk on its crude oil sales. In addition, Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

Condensate – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its condensate purchases.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company may enter into swaps, which fix the AECO or the New York Mercantile Exchange ("NYMEX") price. To help protect against widening natural gas price differentials in various production areas, Cenovus may also enter into swaps to manage the price differentials between production areas and various sales points.

Power – The Company has in place a Canadian dollar denominated derivative contract, which commenced January 1, 2007 for a period of 11 years, to manage a portion of its electricity consumption costs.

Net Fair Value of Risk Management Positions

As at December 31, 2015	Notional Volumes	Term	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 differentials for heavy crudes.
(2) Other financial positions are part of ongoing operations to market the Company's production.

Price Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices 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 in place as at December 31, 2015 and 2014 could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

		2015		2014	
	Sensitivity Range	**Increase**	**Decrease**	Increase	Decrease
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent and WTI Hedges	**(243)**	**245**	(145)	146
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	**80**	**(80)**	5	(5)
Condensate Commodity Price	± US$10 per bbl Applied to Condensate Hedges	**23**	**(23)**	-	-
Natural Gas Commodity Price	± US$1 per Mcf Applied to NYMEX and AECO Natural Gas Hedges	**-**	**-**	(70)	70
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	**19**	**(19)**	19	(19)
Interest Rate Swaps	± 50 Basis Points	**38**	**(46)**	-	-

B) Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada and the translation of the U.S. dollar Partnership Contribution Receivable issued from Canada. As at December 31, 2015, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2014 – US$4,750 million) and US$nil related to the U.S. dollar Partnership Contribution Receivable (2014 – US$nil). In respect of these financial instruments, the impact of changes in the U.S. to Canadian dollar exchange rate would have resulted in a change to foreign exchange (gain) loss as follows:

For the years ended December 31,	**2015**	2014	2013
$0.01 Increase in the U.S. to Canadian Dollar Exchange Rate	**48**	48	48
$0.01 Decrease in the U.S. to Canadian Dollar Exchange Rate	**(48)**	(48)	(48)

C) Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. In addition, to manage the Company's exposure to interest rate volatility, the Company may periodically enter 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.

As at December 31, 2015, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2014 – $nil, 2013 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

D) Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. This credit risk exposure is mitigated through the use of the credit policy approved by the Audit Committee of the Board of Directors governing the Company's credit portfolio and with credit practices that limit transactions according to counterparties' credit quality. Agreements are entered into with major financial institutions with investment grade credit ratings and with large commercial counterparties, most of which have investment grade credit ratings. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. As at December 31, 2015 and 2014, substantially all of the Company's accounts receivable were less than 60 days. As at December 31, 2015, 91 percent (2014 – 91 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties. Cenovus's exposure to its counterparties is within credit policy tolerances.

As at December 31, 2015, Cenovus had one counterparty (2014 – two counterparties) whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, and long-term receivables is the total carrying value.

E) Liquidity Risk

Liquidity risk is the risk that Cenovus will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit, which may be impacted by the Company's credit ratings. As disclosed in Note 30, over the long term, Cenovus targets a Debt to Capitalization ratio between 30 and 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facilities and availability under its shelf prospectuses. As at December 31, 2015, Cenovus had $4.1 billion in cash and cash equivalents, and $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.

Undiscounted cash outflows relating to financial liabilities are:

2015	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	1,702	-	-	-	**1,702**
Risk Management Liabilities (1)	23	5	2	-	**30**
Long-Term Debt (2)	349	2,847	493	8,721	**12,410**
Other (2)	-	3	1	4	**8**

2014	Less than 1 Year	1-3 Years	4-5 Years	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,588	-	-	-	2,588
Risk Management Liabilities (1)	12	4	-	-	16
Long-Term Debt (2)	293	585	2,093	7,724	10,695
Other (2)	-	3	1	4	8

(1) Risk management liabilities subject to master netting agreements.
(2) Principal and interest, including current portion.

33. SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2015**	2014	2013
Interest Paid	**330**	335	409
Interest Received	**19**	33	119
Income Taxes Paid	**933**	46	133

34. COMMITMENTS AND CONTINGENCIES

A) Commitments

As part of normal operations, the Company has committed to certain amounts over the next five years and thereafter as follows:

2015	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage [1]	702	715	780	774	901	23,537	**27,409**
Operating Leases (Building Leases)	116	120	156	153	151	2,647	**3,343**
Product Purchases	84	3	-	-	-	-	**87**
Capital Commitments	61	14	4	-	-	-	**79**
Other Long-Term Commitments	45	31	24	26	15	125	**266**
Total Payments [2]	1,008	883	964	953	1,067	26,309	**31,184**
Fixed Price Product Sales	55	3	-	-	-	-	**58**

2014	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage [1]	522	637	644	823	1,590	23,632	27,848
Operating Leases (Building Leases)	124	122	120	162	160	2,796	3,484
Product Purchases	101	7	-	-	-	-	108
Capital Commitments	90	55	11	2	-	46	204
Other Long-Term Commitments	58	24	21	15	13	116	247
Total Payments [2]	895	845	796	1,002	1,763	26,590	31,891
Fixed Price Product Sales	54	55	3	-	-	-	112

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Contracts undertaken on behalf of the FCCL and WRB are reflected at Cenovus's 50 percent interest.

In 2015, net transportation commitments of $92 million were assumed upon the acquisition of the Company's crude-by-rail terminal.

As at December 31, 2015, there were outstanding letters of credit aggregating $64 million issued as security for performance under certain contracts (2014 – $74 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 32.

B) Contingencies

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.

Decommissioning Liabilities

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recorded a liability of $2,052 million, based on current legislation and estimated costs, related to its crude oil and natural gas properties, refining facilities and midstream facilities. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

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
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.

ADVISORY

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, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2016 price forecast. For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2015 and our Statement of Contingent and Prospective Resources for the year ended December 31, 2015.

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 estimate of contingent resources has not been adjusted for risk based on the chance of development.

Economic contingent resources are those contingent resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. In Cenovus's case, contingent resources were evaluated using the same commodity price assumptions that were used for the 2015 reserves evaluation, which comply with NI 51-101 requirements.

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

Best estimate is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50 percent probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources were estimated for individual projects and then aggregated for disclosure purposes.

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

Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our Annual Information Form and Form 40-F for the year ended December 31, 2015, and our Statement of Contingent and Prospective Resources for the year ended December 31, 2015, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

Forward-looking Information

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "capacity", "could", "should", "focus", "goal", "outlook", "proposed", "potential", "may", "schedule", "on track", "strategy", "forward", "opportunity" or similar expressions and includes suggestions of future outcomes and statements about: our strategy (including all statements under the heading "Our Cenovus" and under sub-headings within such discussion); related milestones and schedules; projected future value; projections for 2016 and future years; forecast operating and financial results; the strength of the Cenovus's position, including in various condition; targets for our Debt to Capitalization and Debt to EBITDA ratios; planned capital expenditures, including the timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves and resources; broadening market access; expected capacities, including for projects, transportation and refining; improving cost structures, forecast cost savings and sustainability thereof; dividend plans and strategy; anticipated timelines for future regulatory, partner or internal approvals; future impact of regulatory measures; forecast commodity prices and expected impact to Cenovus; future use and development of technology, including expected effects on our environmental impact; and projected shareholder return and value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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

2016 guidance, as updated on February 11, 2016, 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 our actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our 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 our 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 our 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; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated business; reliability of our 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 our business; the timing and the costs of well and pipeline construction; our 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 our ability to attract and retain, critical talent; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our Annual Information Form or Form 40-F for the year ended December 31, 2015, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

ABBREVIATIONS

The following abbreviations have been used in this document:

™	trademark of Cenovus Energy Inc.

Crude Oil

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
BOE	barrel of oil equivalent
BOE/d	barrel of oil equivalent per day
MBOE	thousand barrel of oil equivalent
MMBOE	million barrel of oil equivalent
WTI	West Texas Intermediate
WCS	Western Canadian Select
CDB	Christina Dilbit Blend

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	gigajoule
AECO	Alberta Energy Company
NYMEX	New York Mercantile Exchange

NOTES

INFORMATION FOR

SHAREHOLDERS

ANNUAL MEETING

Shareholders are invited to attend the annual meeting to be held on Wednesday, April 27, 2016 at 2 p.m. (Calgary time) at The Westin Calgary, Grand Ballroom, 320 - 4 Avenue SW, Calgary, Alberta, Canada. Please see our management proxy circular available on our website, cenovus.com, for additional information.

TRANSFER AGENT & REGISTRAR

Computershare Investor Services Inc.
8th Floor, 100 University Avenue
Toronto, Ontario M5J 2Y1
Canada
www.investorcentre.com/cenovus
Shareholder inquiries by phone 1.866.332.8898 (North America, English and French) or 1.514.982.8717 (outside North America, English and French).

SHAREHOLDER ACCOUNT MATTERS

For information regarding your shareholdings or to change your address, transfer shares, eliminate duplicate mailings, direct deposit of dividends, etc., please contact Computershare Investor Services Inc.

STOCK EXCHANGES

Cenovus common shares trade on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol CVE.

ANNUAL INFORMATION FORM/FORM 40-F

Our Annual Information Form is filed with the Canadian Securities Administrators in Canada on SEDAR at sedar.com and with the U.S. Securities and Exchange Commission under the Multi-Jurisdictional Disclosure System as an Annual Report on Form 40-F on EDGAR at sec.gov.

NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the NYSE, we are not required to comply with most of the NYSE corporate governance standards and instead may comply with Canadian corporate governance requirements. We are, however, required to disclose the significant differences between our corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE corporate governance standards. Except as summarized on our website, cenovus.com, we are in compliance with the NYSE corporate governance standards in all significant respects.

INVESTOR RELATIONS

Please visit the *Investors* section of our website, cenovus.com for investor information.

Investor inquiries should be directed to:
403.766.7711
investor.relations@cenovus.com

Media inquiries should be directed to:
403.766.7751
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CENOVUS'S BOARD OF DIRECTORS

(as at December 31, 2015)

Michael A. Grandin, Board Chair, Calgary, Alberta [3,7]
Ralph S. Cunningham, Houston, Texas [2,3,5]
Patrick D. Daniel, Calgary, Alberta [1,2,3]
Ian W. Delaney, Toronto, Ontario [2,3,5]
Brian C. Ferguson, Calgary, Alberta [6]
Steven F. Leer, Boca Grande, Florida [1,3,4]
Valerie A.A. Nielsen, Victoria, British Columbia [1,3,4]
Charles M. Rampacek, Dallas, Texas [3,4,5]
Colin Taylor, Toronto, Ontario [1,2,3]
Wayne G. Thomson, Calgary, Alberta [3,4,5]

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Nominating and Corporate Governance Committee
(4) Member of the Reserves Committee
(5) Member of the Safety, Environment and Responsibility Committee
(6) As an officer and a non-independent director, Mr. Ferguson is not a member of any Board committees
(7) Ex-officio non-voting member of all other Board committees

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CENOVUS ENERGY IS A CANADIAN INTEGRATED OIL COMPANY

We're focused on creating long-term value through the development of our vast oil sands assets in northern Alberta, where we drill for oil and use specialized methods to pump it to the surface. We also have established conventional natural gas and oil production in Alberta and Saskatchewan and 50 percent ownership in two U.S. refineries. We're based in Calgary, Alberta and our shares trade on the Toronto and New York stock exchanges under the symbol CVE.

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