cenovus ENERGY

2014 ANNUAL REPORT

CENOVUS
a
CANADIAN OIL COMPANY

At Cenovus, we're committed to being a responsible developer of one of Canada's most valuable resources – the oil sands. We apply fresh, progressive thinking to minimize our impact on the environment while safely producing energy resources the world needs.

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We use a manufacturing approach to produce oil. That approach 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 proud of how we're developing this resource and we stand behind our actions.

- We make safety a priority at our work sites and in the communities where we operate
- We foster a vibrant work environment that encourages diverse and innovative ideas
- We build strong relationships and invest in our communities to help residents share in our success
- We support economic development in Aboriginal communities near our operations – including more than $1 billion we've spent since 2009 on goods and services supplied by Aboriginal businesses
- We value innovative thinking, which helps us continue to improve our environmental performance in areas such as water use, land disturbance and greenhouse gas emissions
- We collaborate with our peers, academics, governments and others to address the issues facing our industry
- We focus on achieving predictable, reliable performance and maintaining the company's financial resilience

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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 122.

Our purpose, promise and values speak to the kind of company we are. The kind of company we want to be. They guide us in how we do our work today and as we grow.

Our purpose *(why we exist)* We inspire bright minds to help fuel world progress.

Our promise *(what we do)* We work collectively to unlock challenging oil resources in a way that makes Canadians proud.

Our values *(how we behave)* Rigorous: We're smart about the way we develop our resources. Respectful: We trust each other to do the right thing. Ready: We have the courage to embrace fresh thinking and new ideas.

We have a rich portfolio of development opportunities, strong project economics and a strong balance sheet.

Our industry-leading oil sands assets support decades of profitable oil growth.

Our track record of strong operational results has allowed us to be a leader in steam-assisted gravity drainage, or SAGD.*

Our manufacturing approach to producing oil is key to our low cost structure and competitive capital efficiencies.

Our focus on innovation means we're continually improving our performance.

Our integrated approach helps improve the long-term stability of our overall cash flow despite the variability in commodity prices.

Our financial strength gives us the flexibility to create value through the development of our vast oil sands resources and supports a sustainable dividend.

**SAGD uses well pairs – one well to inject low-pressure steam to melt the oil and another well to pump the oil to the surface. All of Cenovus's projects in the oil sands use SAGD.*

OUR PROGRESS *in* 2014

Through 2014, we invested substantial time in assessing how to reduce our costs, enhance our operational performance and increase productivity – all with the continued goal of delivering long-term shareholder value. The five initiatives on these two pages also positioned us well to address the ongoing challenges impacting the global energy industry as a result of the oil price decline that began in late 2014. In addition, we implemented immediate actions, discussed in the Message from our President & Chief Executive Officer, to help create greater financial resilience for Cenovus so we can realize our potential when oil prices rebound. We continue to assess what other steps we can take internally to further strengthen our balance sheet.

1

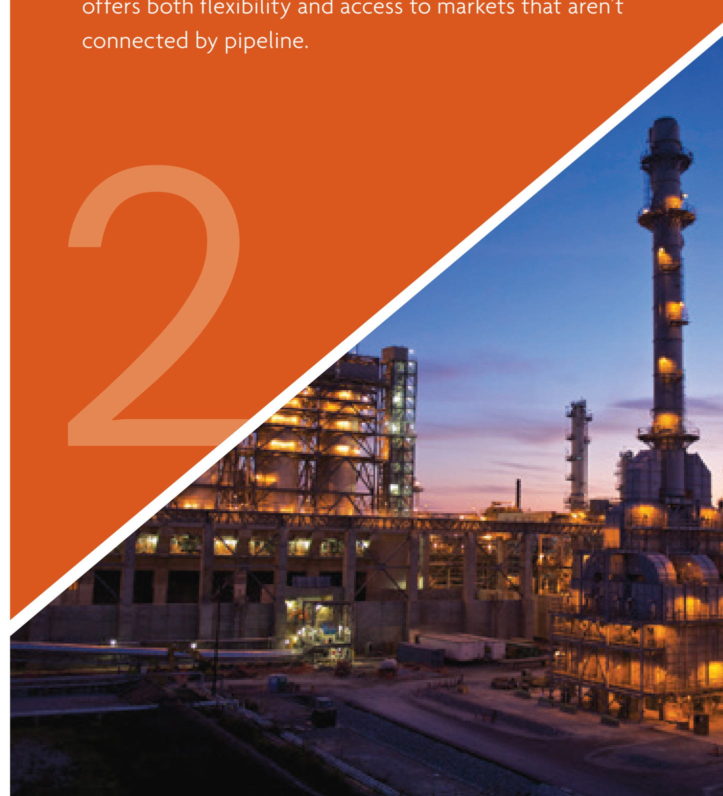
OUR COST STRUCTURES

In early 2014, we established a task force to identify ways to reduce spending and improve operational performance. The task force recommended a number of cost-saving initiatives that will ramp up over the coming years and will have the potential to realize sustained annual savings of hundreds of millions of dollars. These initiatives will create new opportunities to apply our manufacturing approach to producing oil to more areas of our operations – enabling us to increase our productivity and efficiency across our assets and keep our costs down.

2

OUR ABILITY TO REACH NEW MARKETS

We developed and are pursuing a robust strategy to reach new customers and access the best price for our oil. In addition to some Cenovus-specific initiatives that we are evaluating, we added new pipeline capacity and are supportive of all major proposed pipeline projects to the east, west and U.S. Gulf coasts. Rail is also part of our transportation portfolio. We are planning to ship 10 to 20 percent of our volumes by rail over the long term. Rail offers both flexibility and access to markets that aren't connected by pipeline.



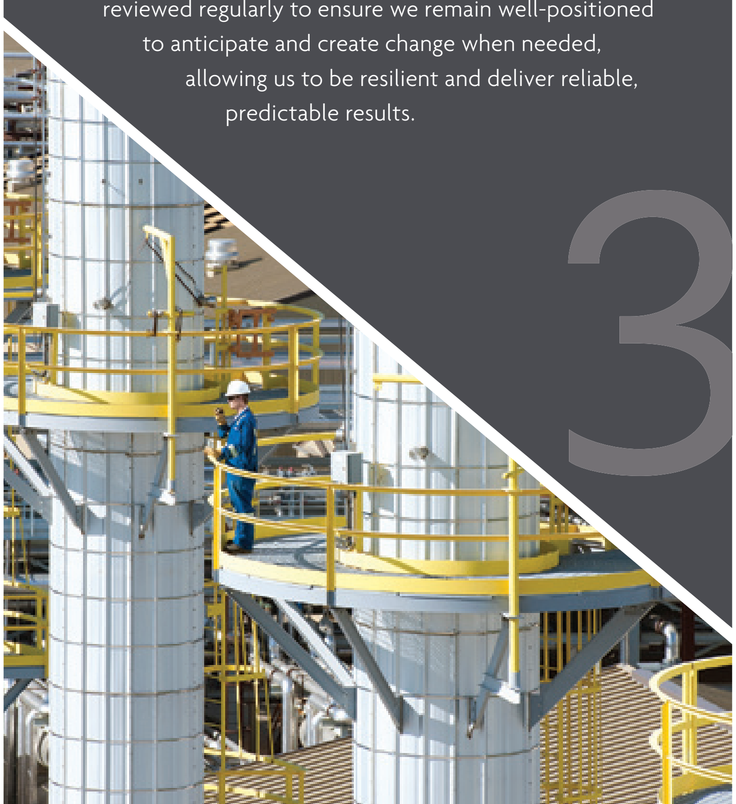
3

OUR PLANNING PROCESS

We broadened our strategic planning process to include a two-part framework to focus on how we unlock our vast resources to realize our potential:

- A long-range outlook, which encompasses the broad opportunities we have the potential to pursue well into the future
- A three-year business plan, which lays out near-term initiatives that enable us to achieve our long-term strategy

We also made adjustments to our key performance indicators (KPIs) to ensure continued alignment with our strategy and business plan. Our KPIs measure our operating and financial performance, linking performance to value creation for our shareholders. The KPIs, business plan and outlook will be reviewed regularly to ensure we remain well-positioned to anticipate and create change when needed, allowing us to be resilient and deliver reliable, predictable results.



4

OUR RESERVOIR MANAGEMENT

We increased our efforts to better manage our oil sands reservoirs as they mature. This led to the implementation of a number of improved techniques at Foster Creek to optimize our use of steam and, ultimately, production performance. Since Foster Creek is our most advanced oil sands project, the learnings and changes to our reservoir management plan implemented there are expected to benefit our other oil sands projects as well.

5

OUR ORGANIZATION STRUCTURE

We identified the need to evolve our organization structure, so we can be even more disciplined about how we execute our manufacturing approach to producing oil. Transitioning to a functional model will help increase our effectiveness and build our depth of expertise – enhancing our ability to manage every stage of our oil sands projects. We began the transition to this new structure in early 2015.

MESSAGE *from our* PRESIDENT & CHIEF EXECUTIVE OFFICER

There is little doubt that 2014 will be remembered for the dramatic drop in oil prices in the latter part of the year, which has caused concern for investors, governments and the people who rely on this industry for their livelihood.

As many long-term industry players will tell you, we are witnessing the cyclical nature of our business. History and experience tell us that oil prices will rebound, so our job is to be ready when they do.

In the meantime, you can expect us to monitor and assess the oil price situation and make decisions about our business accordingly. You can also expect us to deliver consistent performance at our oil sands facilities and keep our costs down. A significant amount of planning went into our 2015 budget. I am focused on making sure that the budget and its execution provide the financial flexibility we need to respond to continued volatility in the markets, while also being able to advance Cenovus's strategy.

In fact, ensuring our financial resilience without compromising on Cenovus's future is my key priority this year. With low oil prices expected to persist through 2015 and into 2016, we are taking the steps that we believe will provide the best value for you, our shareholders, for the next several years. That's why, after careful consideration and discussion with the Board, we completed a $1.5 billion equity issue in early 2015 that will allow us to continue to invest in our high-return projects and maintain our investment grade credit ratings.

We also implemented other measures to help ensure we are well-positioned to be resilient through the downturn and realize our potential when oil prices rebound. These measures included:

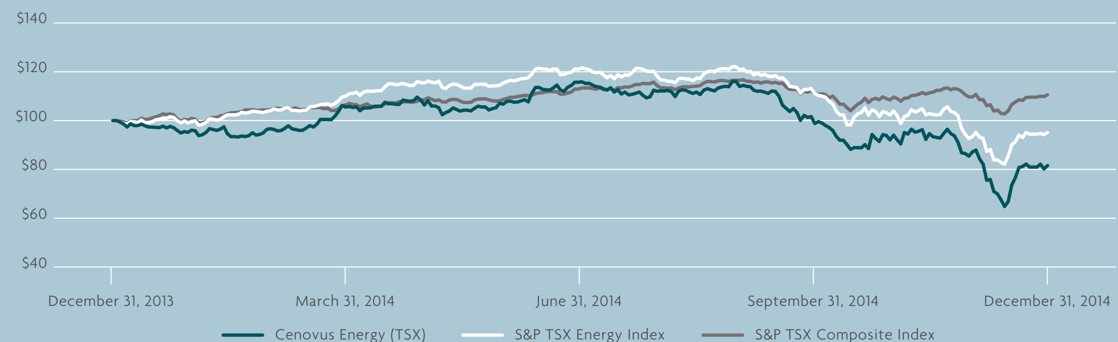
- Reducing our planned 2015 capital expenditures by about 40 percent compared with 2014
- Curtailing our discretionary spending across the company
- Reducing our workforce by 15 percent
- Introducing a discounted Dividend Reinvestment Plan (DRIP) to give shareholders the opportunity to reinvest their dividends by purchasing more common shares at a discount

Throughout the year, we will continue to look for ways to further strengthen our balance sheet and will continue to evaluate our dividend with the Board.

Well before the drop in oil prices, we made strategic decisions in key areas to help drive performance, increase productivity and, ultimately, deliver greater shareholder value over the long term. As you will have seen on pages 2 and 3, we identified cost-saving initiatives and ways to improve our operational performance, we developed a strategy to reach new markets so we can receive the best possible price for our oil, we revised our planning process and our performance metrics, and we started to evolve our organization structure.

During the first nine months of last year, Cenovus's stock price trended upwards and was generally in line with our peer group. Strong financial results, combined with consistent operations at

TOTAL SHAREHOLDER RETURN 2014



Cumulative total shareholder return for $100 invested (assuming quarterly reinvestment of dividends), over the period December 31, 2013 to December 31, 2014.

our two oil sands drilling projects, Foster Creek and Christina Lake, contributed to this performance. Unfortunately, our share price weakened in the latter part of the year and we underperformed our peer group after we announced higher than expected capital costs for phases F, G and H at Foster Creek.

We remain optimistic about our future performance and development opportunities at Foster Creek and Christina Lake, and our potential to create long-term shareholder value. There's plenty of reason for that optimism. We have highly-skilled, talented people, an integrated portfolio, rich development opportunities and a solid balance sheet.

While the impact of low oil prices is top of mind, it's important to acknowledge the successes we had as a company last year. 2014 was a solid year from an operational and financial perspective. We saw combined oil sands production at Foster Creek and Christina Lake increase by 25 percent compared with 2013. We generated cash flow of about $3.5 billion, or $4.59 per share on a diluted basis, and increased our dividend by 10 percent to $1.0648 per share.

For last year's successes and for the efforts underway this year to overcome our current challenges, I thank the men and women of Cenovus. They continue to live up to and deliver on our commitments, embrace innovation by continuously making improvements to our operations, and ensure that Cenovus is a great place to work.

And I would like to thank the members of the Executive Team and our Board for their expertise and guidance throughout this past year.

2015 will, without a doubt, be an interesting year and I fully expect to see new challenges. But I also fully expect to see new opportunities – opportunities that come when the industry is forced to rethink, reexamine and readjust.

We are ready and well-positioned to realize our potential.

BRIAN C. FERGUSON

President & Chief Executive Officer

A SNAPSHOT *of our* YEAR

HEALTH AND SAFETY

- We had our strongest year for safety – achieving an 18 percent improvement in workplace safety. We worked about 45 million hours, the highest number of hours worked in Cenovus's history, with the lowest number of contractor incident rates.
- Our Weyburn asset was recognized by WorkSafe Saskatchewan as the 2014 Safe Employer of the year.
- We opened a new Foster Creek emergency services building, which improves our capability to respond to emergency events in the area.

OPERATIONS

- We increased oil sands production by 25 percent.
- Our non-fuel operating costs per barrel decreased by 14 percent at our oil sands projects.
- We received regulatory approval for our Grand Rapids and Telephone Lake oil sands projects and our Foster Creek phase J expansion.
- We increased our expected capital costs for the next phases at Christina Lake and Foster Creek, including plant optimizations, to enhance long-term plant reliability and production efficiencies. These capital costs remain competitive within the industry.
- We reached a major milestone at Foster Creek in September – with phase F achieving first oil production.
- We increased our proved bitumen reserves by seven percent to nearly two billion barrels of oil due to an area expansion approval at Foster Creek and improved well performance at Christina Lake.
- Our total proved reserves reached almost 2.4 billion barrels of oil equivalent, up four percent from the previous year.

Steam to oil ratio (SOR) measures the amount of steam used to produce a barrel of oil from the oil sands. A low SOR is a reflection of the efficiency with which we run our facilities and the quality of the reservoir.

- Christina Lake's SOR of 1.8 remains the lowest in the industry. Foster Creek's SOR of 2.6 is also below the industry average of approximately 3.0. A low SOR is not only good for the environment, it's also good for the bottom line. It means we burn less natural gas, use less water and need less infrastructure.

See the Management's Discussion and Analysis starting on page 10 for complete financial and operating results. There is also a table with our financial and operating highlights on cenovus.com/annualreport.

Total cash flow
$3.5 BILLION
$4.59 per share on a diluted basis

Total capital investment
$3.1 BILLION
focused on advancing our oil sands growth projects at Foster Creek and Christina Lake

25% INCREASE
oil sands production

REFINING

We have 50 percent ownership in two U.S. refineries – Wood River in Illinois and Borger in Texas.

- We experienced an 82 percent decline in operating cash flow from refining as a result of:
  - Lower average market crack spreads due to a narrowing of the Brent-WTI price differential
  - Higher heavy crude oil feedstock costs
  - A significant decrease in benchmark crude oil prices in the latter part of the year
- Our refineries processed an average of 423,000 gross barrels per day of crude oil.

TRANSPORTATION

- In late 2014 and early 2015 we began delivering on new pipelines in Alberta and the southern U.S. to help transport our oil to market. An additional new pipeline brings diluent to our oil sands facilities to blend with the oil so it can flow on pipelines.
- We moved an average of 10,000 barrels per day of crude oil by rail, including 47 unit train shipments.

ENVIRONMENT AND INNOVATION

- We reworked our environment strategy to include a stronger long-term focus on technologies that will reduce our environmental impacts and address environmental concerns.
- We joined the Water Environmental Priority Area (EPA) with Canada's Oil Sands Innovation Alliance (COSIA). COSIA is an alliance of 13 oil sands companies collaborating on technology and innovation to improve the environmental performance of the industry. Cenovus is now actively participating in the land, greenhouse gases and water environmental priority areas.

Our SkyStrat™ drilling rig is a scaled-down version of a stratigraphic drilling rig that can be flown to remote locations by helicopter. By reducing the need to build access roads, the rig will help decrease our environmental footprint and operating costs in those areas.

- We drilled 14 wells using this technology at our Telephone Lake oil sands project in the summer of 2014.
- We commissioned a second SkyStrat™ drilling rig in late 2014, which we used to drill seven wells in early 2015.

FINANCIAL

- Our cash flow decreased four percent from last year, to about $3.5 billion, as our 19 percent increase in upstream operating cash flow was more than offset by a significant decrease in operating cash flow from our refining operations.
- Total capital investment was $3.1 billion.
- Our 2014 closing share price decreased by 21 percent compared with year-end 2013, impacted primarily by weaker commodity prices and our announcement of higher than expected capital costs for phases F, G and H at Foster Creek.
- We increased our annual dividend by 10 percent to $1.0648 per share.

14% DECREASE
non-fuel operating costs at our oil sands projects

18% IMPROVEMENT
in workplace safety measured by the frequency of total recordable injuries

423,000
barrels of oil per day gross, on average, processed at our refineries

ABORIGINAL RELATIONS

We work to build strong relationships with Aboriginal communities in our operating areas.

- We spent over $383 million doing business with Aboriginal companies.
- We signed two new long-term agreements with Aboriginal communities in the areas where we operate. These agreements outline a number of aspects of our relationships including consultation and engagement, community investment funding, economic and business development, employment and training, and other issues specific to each community.

COMMUNITY INVOLVEMENT

We want communities to be better off as a result of us being there. Part of that commitment is to give back.

- We invested $16 million in our communities. Examples include:
  - Giving over $2 million to support literacy initiatives across our operating areas, by partnering with school divisions and supporting reading programs and summer literacy camps
  - Investing in a wide range of emergency services, programs and safety training as part of our commitment to safety in our communities
  - Contributing $4 million (total of what our employees gave, and the Cenovus match) to more than 1,090 organizations through our employee giving programs

SUSTAINABILITY

- We were acknowledged for our strong risk management, transparency, stakeholder engagement, environmental initiatives and employee retention. Recognitions include:
  - Dow Jones Sustainability World Index for the third year in a row (the only North American oil and gas company) and the North American Index for the fifth year in a row
  - Canada 200 Climate Disclosure Leadership Index
  - RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction
  - FTSE4Good Index
  - MSCI Global Sustainability Index
  - IR Magazine Canada Award for best sustainability practice

Over
$383 MILLION
amount spent doing business with Aboriginal companies

$16 MILLION
total investment in our communities

MESSAGE *from our* BOARD CHAIR

As I sit down to write this year's message, the price of oil is still around $50 per barrel, down from $100, and our stock price is below its initial trading value, set when Cenovus was launched more than five years ago. While the short-term outlook is unclear, what is certain is that now is the time to critically assess where we are as well as our path forward. As the shareholders' representative, one of the Board's responsibilities is to ensure, to the best of its ability, the long-run success of Cenovus. While we undertake a number of ongoing activities to discharge that responsibility, I thought four would be of particular interest at this time.

One of our most important tasks is to appoint and assess senior management. We meet regularly with the Chief Executive Officer and other Executive Officers, both during and between Board meetings. Based on results to date of activities over which management has control, we have complete confidence in Brian Ferguson and his team.

The Board also regularly assesses Cenovus's business strategy. We meet with management on three separate occasions each year specifically to review, question and challenge different elements of that strategy. Notwithstanding current economic conditions in the global oil sector, we have confidence that Cenovus's stated strategy remains the best one for the company in the long run.

To realize long-run benefits, companies must survive short-run troughs in the business cycle. To do so requires sound financial planning, the ability to adjust to challenging market conditions, and, on occasion, make difficult decisions. Your Directors, along with the members of the Executive Team, have worked through a number of other major down cycles. That experience enabled us to ensure that well before the start of this low-price commodity environment, management had developed the financial capacity necessary to withstand scenarios in which prices reached lower than expected levels. Contingency plans, to ensure continued financial resiliency should prices remain near current levels for a prolonged period of time, have been established and launched. We have confidence in management's financial strategy.

Finally, it is also important to ensure that you have a well-constructed, balanced and effective Board. All of Cenovus's current Directors were in place at the time Cenovus was created and we believed it important to have a stable Board for the first years of the company's life. As a result, by next year, the majority will be at or over the age of 70. Now that the company is well established, we believe that through good succession planning we should have a more balanced age distribution going forward. Accordingly, in 2014 we embarked upon a renewal program to ensure that your Board continues to have the necessary skills and desirable balance of age and gender to discharge its ongoing responsibilities.

In closing, we believe that Cenovus is pursuing a corporate strategy that best suits its strengths, has a management team well-suited to running the business under changing conditions and a Board that is doing its best to advise, challenge and assess management's decisions – all with the objective of achieving the long-run success of the company. We hope you agree that Cenovus remains well-positioned to realize its potential.

Respectfully submitted on behalf of the Board,

MICHAEL A. GRANDIN
Board Chair

MANAGEMENT'S DISCUSSION *and* ANALYSIS

For the Year Ended December 31, 2014

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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 11, 2015, should be read in conjunction with our December 31, 2014 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 11, 2015, 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 11, 2015. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

Non-GAAP Measures

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

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On December 31, 2014, we had a market capitalization of approximately $18 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production in 2014 was approximately 203,500 barrels per day and our average natural gas production was 488 MMcf per day. Our refineries processed an average of 423,000 gross barrels per day of crude oil feedstock into an average of 445,000 gross barrels per day of refined products.

OUR KEY MESSAGE FOR 2014

Up until the fourth quarter, 2014 could be described as a period of relative financial stability. Commodity prices were relatively strong and were expected to remain so, and our financial results for the first nine months reflected this. At the onset of the fourth quarter, there was a substantial decline in the commodity price environment, which significantly impacted our fourth quarter financial results. Between September 30, 2014 and December 31, 2014, crude oil and refined product benchmark prices fell between 40 and 55 percent and the forward prices for 2015 show little sign of near-term improvement. Although declining commodity prices negatively impacted our 2014 results, we continued to make operational progress as shown by our growing crude oil production.

2015 will be a challenging time for our industry. However, Cenovus remains well positioned to manage through these volatile times. We have significantly reduced our 2015 capital budget to exercise further capital restraint in this low crude oil price environment. For more information we direct our readers to review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

OUR STRATEGY

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a sustainable dividend. Inherent to our strategy is a focus on protecting our financial resilience by evaluating on a regular basis our capital investment plans, dividend plans and other relevant factors.

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

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

Oil Development

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

We anticipate increasing our annual net crude oil production, including our conventional crude oil operations, to more than 500,000 barrels per day by fully developing our producing projects and those that currently have regulatory approval.

Execution Excellence

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

Financial Strength

We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. This is a significant reduction from 2014 levels in response to the current low crude oil price environment. A portion of our capital investment is expected to be internally funded through cash flow generated from our crude oil, natural gas and refining operations. The remainder is expected to be funded by prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

Dividend

The declaration of dividends is at the sole discretion of our Board and is considered each quarter. We paid dividends of $1.0648 per share in 2014 (2013 – $0.968 per share; 2012 – $0.88 per share).

Innovation and the Environment

Technology development, research activities and understanding our impact on the environment continue to play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technology with the goals of increasing recoveries from our reservoirs, while reducing the amount of water, natural gas and electricity consumed in our operations, potentially reducing costs and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches. We have a track record of developing innovative solutions that unlock challenging crude oil resources, 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:

	2014 OWNERSHIP INTEREST *(percent)*	2014 NET PRODUCTION VOLUMES *(bbls/d)*	2014 GROSS PRODUCTION VOLUMES *(bbls/d)*
Existing Projects			
Foster Creek	50	59,172	118,344
Christina Lake	50	69,023	138,046
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. Narrows Lake is under development. These projects are located in the Athabasca region of northeastern Alberta. Two of our 100 percent owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions, respectively.

Conventional

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

	2014	
($ millions)	CRUDE OIL [1]	NATURAL GAS
Operating Cash Flow	1,360	508
Capital Investment	812	28
Operating Cash Flow Net of Related Capital Investment	548	480

(1) Includes NGLs.

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

Approximately 70 percent, or 4.5 million net acres, of our conventional land is owned in fee title, which means we own the mineral rights. About 50 percent of our total conventional production comes from our fee lands. We do not pay third-party royalties where we have working interest production from fee lands. Rather, we pay mineral tax to the government that is generally lower than royalties paid to mineral interest owners. In addition, a portion of our fee lands are leased to third parties which may give rise to royalty income. This leased land resulted in Operating Cash Flow of approximately $150 million in 2014.

Refining and Marketing

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

	OWNERSHIP INTEREST *(percent)*	2014 GROSS NAMEPLATE CAPACITY *(Mbbls/d)*
Wood River	50	314
Borger	50	146

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

($ millions)	2014
Operating Cash Flow	211
Capital Investment	163
Operating Cash Flow Net of Related Capital Investment	**48**

2014 OPERATING AND FINANCIAL HIGHLIGHTS

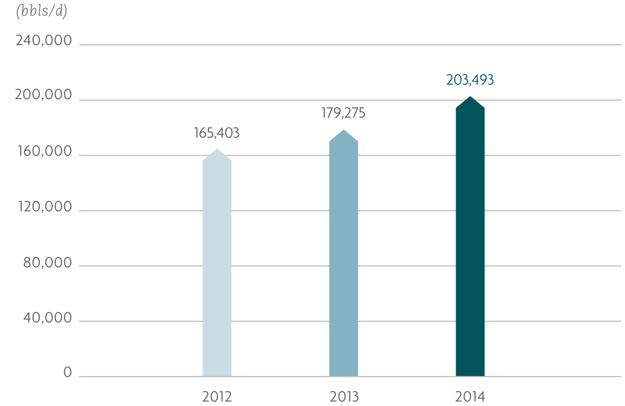
In general, integration of our business provides some protection from commodity price fluctuations. In a period when crude oil price differentials widen and Operating Cash Flow from our upstream operations decreases, our refining operations benefit from lower heavy crude oil feedstock costs. In 2014, we experienced strong commodity prices for the first nine months which very quickly changed as crude oil and refined product benchmark prices fell between 40 and 55 percent from September 30, 2014 to December 31, 2014. The significant decline in prices had a significant negative impact on our fourth quarter financial results, including the valuation of our crude oil and refined product inventories and negatively impacted our full year financial results.

In 2014, other significant developments include increasing our crude oil production by 14 percent, growing our reserves, receiving regulatory approval for Grand Rapids and Telephone Lake, completing our planned capital program and increasing our market access capability through rail and pipeline commitments.

OPERATIONAL RESULTS

Total crude oil production averaged 203,493 barrels per day, up 14 percent from 2013.

TOTAL CRUDE OIL PRODUCTION VOLUMES
(bbls/d)



Crude oil production from our Oil Sands segment averaged 128,195 barrels per day, an increase of 25 percent, primarily driven by a 40 percent increase in production at Christina Lake. Average production at Christina Lake increased to 69,023 barrels per day due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance of our facilities, and better reservoir performance with strong base well performance and a lower steam to oil ratio ("SOR"). Phase E increased nameplate production capacity to 138,000 gross barrels per day.

Foster Creek production averaged 59,172 barrels per day, up 11 percent due to improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. We also achieved first production from phase F in September, with ramp up expected to take approximately eighteen months. Phase F is our eleventh oil sands expansion phase.

Our Conventional crude oil production averaged 75,298 barrels per day, a slight decrease from 2013. An increase in production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake was offset by expected natural declines and the impact of divestitures of non-core assets, including the sale of our Lower Shaunavon asset in the second half of 2013 and certain of our Bakken and Wainwright assets in 2014. The annual average crude oil production from these non-core assets was 2,173 barrels per day in 2014 (2013 – 5,223 barrels per day).

Our proved bitumen reserves increased seven percent to approximately 2.0 billion barrels and our proved plus probable bitumen reserves rose 30 percent to 3.3 billion barrels. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

Crude oil processed and refined product output declined compared with 2013 primarily due to an unplanned coker outage at our Borger refinery and a planned turnaround at Wood River. We processed an average of 423,000 gross barrels per day (2013 – 442,000 gross barrels per day) of crude oil, of which 199,000 gross barrels per day (2013 – 222,000 gross barrels per day) was heavy crude oil. We produced 445,000 gross barrels per day of refined products, a decrease of 18,000 gross barrels per day, or four percent.

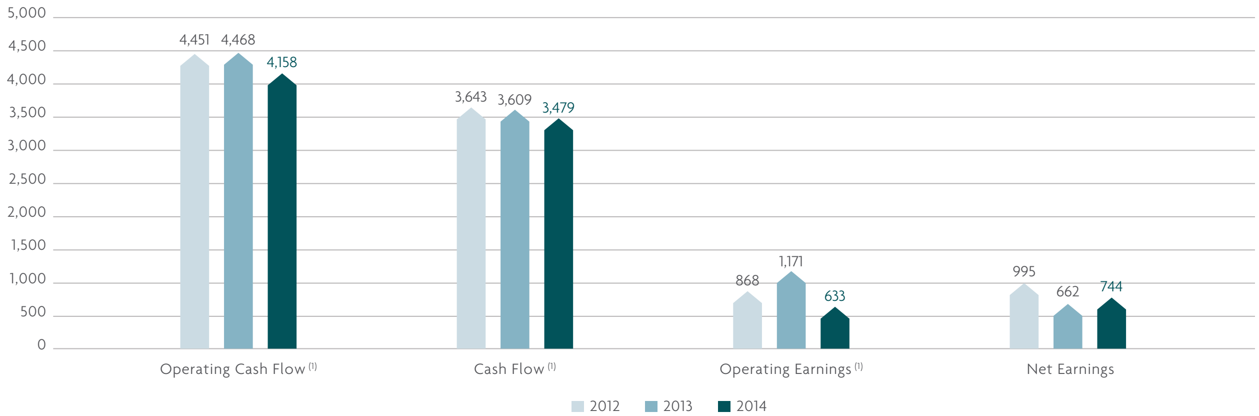
Other significant operational results in 2014 compared with 2013 include:

- Receiving regulatory approval for phase J, a 50,000 gross barrels per day phase, at Foster Creek; a 180,000 gross barrels per day SAGD operation at our Grand Rapids project; and a 90,000 gross barrels per day SAGD project at Telephone Lake. These approvals bring our expected production capacity on our producing properties and on projects with regulatory approval to over 500,000 net barrels per day;
- Receiving regulatory approval for expansion of the Foster Creek development area;
- The disposition of certain Bakken and Wainwright assets for net proceeds of approximately $269 million;
- Increasing rail takeaway capacity for crude oil to approximately 30,000 barrels per day at year end. In 2014, we transported an average of 10,000 barrels per day of crude oil by rail, including 47 unit train shipments; and
- Committing to additional pipeline transportation agreements to ensure adequate shipping capacity for our growing production.

FINANCIAL RESULTS

OPERATING CASH FLOW, CASH FLOW, OPERATING EARNINGS AND NET EARNINGS

($ millions)



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

Financial highlights for 2014 compared with 2013 include:

Revenues

Revenues of $19,642 million, an increase of $985 million or five percent, as a result of:

- Our average crude oil and natural gas sales prices (excluding financial hedging) rising six percent to $71.35 per barrel and 37 percent to $4.37 per Mcf, respectively;
- Crude oil sales volumes increasing 12 percent; and
- A rise in condensate volumes used in blending, consistent with the increase in production.

These increases to revenues were partially offset by:

- A decrease in revenues from our refining operations primarily due to lower refined product prices and declines in refined product output, partially offset by the weakening of the Canadian dollar;
- Higher royalties primarily due to an increase in crude oil sales prices and volumes; and
- Expected declines in natural gas production volumes.

Operating Cash Flow

Operating Cash Flow of $4,158 million declined seven percent from 2013 primarily due to an 82 percent decrease in Operating Cash Flow from our Refining and Marketing segment. The decrease was due to lower average market crack spreads, higher heavy crude oil feedstock costs relative to the West Texas Intermediate ("WTI") benchmark price, higher operating expenses and a decrease in refined product output related to the planned and unplanned outages, and an inventory write-down of $113 million. Generally, when crude oil price differentials are widening, our refining Operating Cash Flow increases. However, with the sharp decline in prices during the fourth quarter, the cost of heavy crude oil feedstock processed was higher than the refined product pricing we realized.

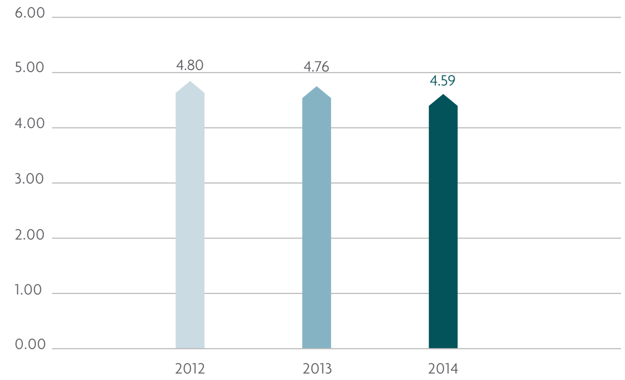
The decrease in Operating Cash Flow from our Refining and Marketing segment was partially offset by a 19 percent increase in upstream Operating Cash Flow to $3,947 million. The increase was primarily due to higher average crude oil and natural gas sales prices and a rise in crude oil sales volumes, partially offset by higher royalties, an increase in operating expenses and an inventory write-down of $18 million.

Cash Flow

Cash Flow decreased four percent to $3,479 million. Cash Flow was lower primarily due to a decline in Operating Cash Flow as discussed above and a decrease in interest income, partially offset by a decline in finance costs, lower current income tax and the absence of a pre-exploration expense in 2014 compared with 2013.

CASH FLOW PER SHARE – DILUTED

($/share)



Operating Earnings

Operating Earnings decreased $538 million, or 46 percent, primarily due to:

- A decrease in Cash Flow as discussed above;
- Goodwill impairment of $497 million due to declines in crude oil prices and a slowing down of the Pelican Lake development plan;
- Inventory write-downs of $131 million discussed above in Operating Cash Flow due to a decline in prices;
- Exploration expense of $86 million related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible; and
- Property, plant and equipment ("PP&E") impairment of $65 million primarily related to impaired equipment.

Other significant non-cash items impacting Operating Earnings include higher depreciation, depletion and amortization ("DD&A") and lower deferred income taxes.

Net Earnings

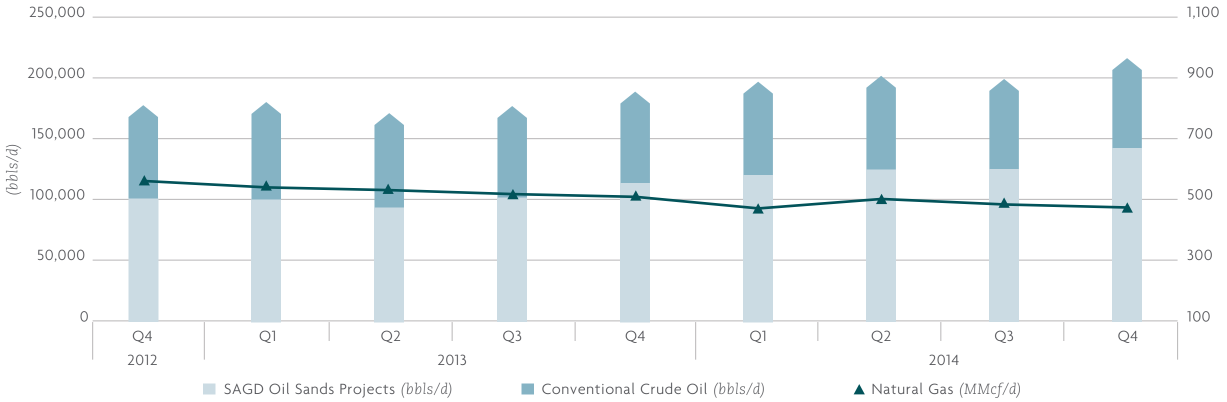
Net Earnings increased $82 million, or 12 percent, to $744 million. The lower Operating Earnings discussed above was more than offset by unrealized risk management gains compared with losses in 2013, gains on the sale of non-core assets and a foreign exchange loss realized in 2013 related to the Partnership Contribution Receivable. The increase to Net Earnings was partially offset by higher non-operating unrealized foreign exchange losses.

Capital Investment

Capital investment was $3,051 million, a decrease of six percent. Capital investment in our Conventional segment declined primarily at Pelican Lake reflecting our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program, partially offset by the increase in capital investment at Christina Lake.

OPERATING RESULTS

TOTAL PRODUCTION VOLUMES



CRUDE OIL PRODUCTION VOLUMES

(barrels per day)	2014	PERCENT CHANGE	2013	PERCENT CHANGE	2012
Oil Sands					
Foster Creek	**59,172**	**11%**	53,190	(8%)	57,833
Christina Lake	**69,023**	**40%**	49,310	55%	31,903
	128,195	**25%**	102,500	14%	89,736
Conventional					
Pelican Lake	**24,924**	**3%**	24,254	8%	22,552
Other Heavy Oil	**14,622**	**(9%)**	15,991	–%	16,015
Total Heavy Oil	**39,546**	**(2%)**	40,245	4%	38,567
Light and Medium Oil	**34,531**	**(3%)**	35,467	(2%)	36,071
NGLs [1]	**1,221**	**15%**	1,063	3%	1,029
	75,298	**(2%)**	76,775	1%	75,667
Total Crude Oil Production	**203,493**	**14%**	179,275	8%	165,403

(1) NGLs include condensate volumes.

Production from Christina Lake increased significantly in 2014 due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance of our facilities, and better reservoir performance with strong base well performance and a lower SOR. Our 2014 planned turnaround at phases A and B was successfully completed in the second quarter with minimal impact to production as volumes during that time were processed through the phase C, D and E plant.

Foster Creek production increased as a result of improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. In 2014, we improved our downhole instrumentation, enhanced steam distribution across the field and improved how steam moves along individual wells. In addition, we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. In September, we achieved first production from phase F, with ramp up expected to take approximately eighteen months. The planned turnaround in 2014, which was smaller in scale compared with the 2013 planned major turnaround, had a minimal impact on production.

In total, our Conventional crude oil production decreased slightly in 2014. Increased production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake was more than offset by expected natural declines and the divestiture of non-core assets. Pelican Lake production was higher due to an increased response from the polymer flood program and additional infill wells coming on stream, partially offset by a planned turnaround.

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	2014	2013	2012
Conventional	**466**	508	564
Oil Sands	**22**	21	30
	488	529	594

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

OPERATING NETBACKS

	CRUDE OIL (1) *($/bbl)*			NATURAL GAS *($/Mcf)*		
	2014	2013	2012	2014	2013	2012
Price (2)	**71.35**	67.01	65.79	**4.37**	3.20	2.42
Royalties	**6.18**	5.01	6.29	**0.08**	0.04	0.03
Transportation and Blending (2) (3)	**2.98**	3.12	2.65	**0.12**	0.11	0.10
Operating Expenses	**15.59**	15.65	13.90	**1.23**	1.16	1.10
Production and Mineral Taxes	**0.50**	0.48	0.56	**0.05**	0.02	0.01
Netback Excluding Realized Risk Management	**46.10**	42.75	42.39	**2.89**	1.87	1.18
Realized Risk Management Gain (Loss)	**0.50**	1.09	1.39	**0.04**	0.32	1.14
Netback Including Realized Risk Management	**46.60**	43.84	43.78	**2.93**	2.19	2.32

(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 $30.49 per barrel (2013 – $28.33 per barrel; 2012 – $26.72 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 or 2012. See the Oil Sands and Conventional Reportable Segments sections of this MD&A for more details.

In 2014, our average crude oil netback, excluding realized risk management gains and losses, increased $3.35 per barrel primarily due to higher sales prices, consistent with the rise in the Western Canadian Select ("WCS") and Christina Dilbit Blend ("CDB") benchmark prices and the weakening of the Canadian dollar. The weakening of the Canadian dollar in 2014 had a positive impact on our crude oil price of approximately $5 per barrel using the foreign exchange rate at December 31, 2014. Our average natural gas netback, excluding realized risk management gains and losses, increased $1.02 per Mcf primarily due to higher sales prices consistent with the rise in the AECO benchmark price.

REFINING (1)

	2014	PERCENT CHANGE	2013	PERCENT CHANGE	2012
Crude Oil Runs *(Mbbls/d)*	**423**	**(4%)**	442	7%	412
Heavy Crude Oil	**199**	**(10%)**	222	12%	198
Refined Product *(Mbbls/d)*	**445**	**(4%)**	463	7%	433
Crude Utilization *(percent)*	**92**	**(5%)**	97	6%	91

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

In 2014, crude oil runs and refined product output declined as a result of an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery. In 2013, an unplanned hydrocracker outage at our Wood River refinery negatively impacted volumes, however, to a lesser extent.

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

SELECTED BENCHMARK PRICES AND EXCHANGE RATES (1)

	Q4 2014	Q4 2013	2014	2013	2012
Crude Oil Prices *(US$/bbl)*					
Brent					
Average	**76.98**	109.35	**99.51**	108.76	111.70
End of Period	**57.33**	110.80	**57.33**	110.80	111.11
WTI					
Average	**73.15**	97.46	**93.00**	97.97	94.20
End of Period	**53.27**	98.42	**53.27**	98.42	91.82
Average Differential Brent-WTI	**3.83**	11.89	**6.51**	10.79	17.50
WCS (2)					
Average	**58.91**	65.26	**73.60**	72.77	73.17
End of Period	**37.59**	74.80	**37.59**	74.80	59.16
Average Differential WTI-WCS	**14.24**	32.20	**19.40**	25.20	21.03
Condensate (C5 @ Edmonton)					
Average	**70.57**	94.22	**92.95**	101.69	100.93
Average Differential WTI-Condensate (Premium)/Discount	**2.58**	3.24	**0.05**	(3.72)	(6.73)
Average Differential WCS-Condensate (Premium)/Discount	**(11.66)**	(28.96)	**(19.35)**	(28.92)	(27.76)
Average Refined Product Prices *(US$/bbl)*					
Chicago Regular Unleaded Gasoline ("RUL")	**81.26**	103.52	**107.40**	116.35	119.58
Chicago Ultra-low Sulphur Diesel ("ULSD")	**101.48**	121.98	**117.55**	126.31	126.58
Refining Margin 3-2-1 Average Crack Spreads *(US$/bbl)*					
Chicago	**14.60**	12.29	**17.61**	21.77	27.76
Group 3	**13.28**	10.66	**16.27**	20.80	28.56
Natural Gas Average Prices					
AECO *(C$/Mcf)*	**4.01**	3.15	**4.42**	3.17	2.41
NYMEX *(US$/Mcf)*	**4.00**	3.60	**4.42**	3.65	2.79
Basis Differential NYMEX-AECO *(US$/Mcf)*	**0.44**	0.59	**0.40**	0.58	0.38
Foreign Exchange Rates *(US$ per C$1)*					
Average	**0.881**	0.953	**0.905**	0.971	1.001

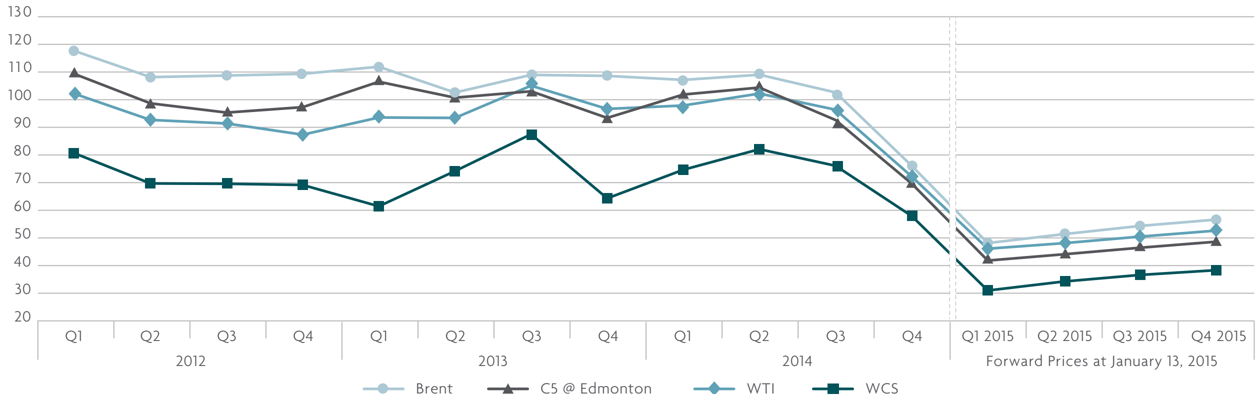
(1) These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.
(2) The Canadian dollar average WCS benchmark price for 2014 was $81.33 per barrel (2013 – $74.94 per barrel; 2012 – $73.10 per barrel), fourth quarter average WCS benchmark price was $66.87 per barrel (Q4 2013 – $68.48 per barrel).

Crude Oil Benchmarks

In the fourth quarter of 2014, there was a significant decrease in crude oil and refining benchmark prices. The end of period Brent, WTI and WCS benchmark prices at December 31, 2014 decreased 39 percent, 42 percent and 50 percent, respectively, compared with September 30, 2014. In addition, average end of period refined product prices and 3-2-1 market crack spreads declined 47 percent and 87 percent at December 31, 2014 compared with September 30, 2014.

In the fourth quarter of 2014, the declines were primarily due to slowing global economic conditions outside of the U.S. combined with strong growth in North American crude oil supply and the unexpected return of Libyan crude oil supply. In addition, the Organization of Petroleum Exporting Countries ("OPEC") decided to maintain its level of crude oil output. The OPEC decision signals a desire to protect market share as opposed to maintaining price stability. We anticipate continued volatility in crude oil prices and expect prices to remain relatively low in 2015 as shown below. Refer to the Outlook section of this MD&A for our outlook on commodity prices over the next twelve months.

CRUDE OIL BENCHMARKS
(average US$/bbl)



The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. In 2014, the average price of Brent crude oil decreased by US$9.25 per barrel (nine percent). In the third quarter of 2014, Brent crude oil prices started to decline due to slowing global economic conditions outside of the U.S. slowing crude oil demand and strong growth in North American crude oil supply creating a global imbalance of supply and demand. In the fourth quarter of 2014, the imbalance was furthered with the decision made by OPEC to maintain their level of crude oil output resulting in the continued decline of Brent crude oil 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 WTI-Brent average differential narrowed in 2014 by US$4.28 per barrel (40 percent) as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved severe congestion that developed in the first half of 2013.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential narrowed by US$5.80 per barrel (23 percent) primarily due to capacity additions on existing pipelines as well as improved performance across the pipeline network used to export crude oil to U.S. refineries. Growing rail capacity helped to relieve congestion by providing access to existing and new U.S. heavy oil refining markets. In addition, heavy oil demand increased as new coker capacity in the Chicago area came online earlier this year and continues to ramp up.

Blending condensate with bitumen and heavy oil enables our production to be transported though 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. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Compared with 2013, the WTI-Condensate average differential narrowed by US$3.77 per barrel as new pipeline capacity from the U.S. Gulf Coast to western Canada decreased the cost of importing condensate. The WCS-Condensate average differential narrowed by US$9.57 per barrel primarily due to improved transportation infrastructure for both condensate imports into Alberta and heavy crude oil exports to market.

Refining Benchmarks

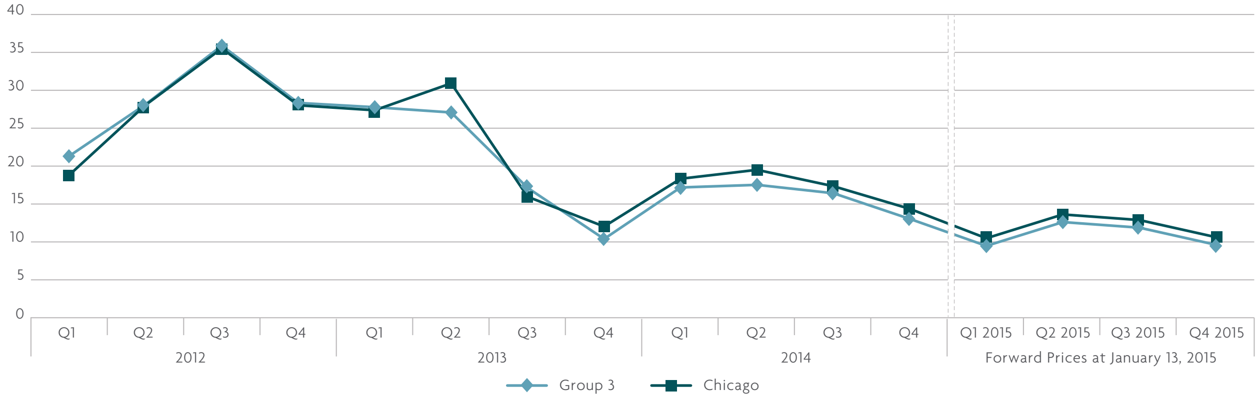
The Chicago RUL and Chicago ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 crack spread. The 3-2-1 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded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

Average inland refined product prices decreased in 2014 due to weaker global crude oil pricing. Average inland market crack spreads fell compared with 2013 due to the narrowing of the Brent-WTI differential.

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

REFINING 3-2-1 CRACK SPREAD BENCHMARKS

(average US$/bbl)



Other Benchmarks

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

A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on all of our revenues as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmarks. Similarly, our refining results are in U.S. dollars, and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment. In 2014, the Canadian dollar weakened by $0.07 relative to the U.S. dollar due to weaker commodity prices and interest rates rising faster in the U.S. compared with Canada as the U.S. economy improved. The weakening of the Canadian dollar by seven percent in 2014 as compared with 2013 had a positive impact of approximately $1.5 billion on our revenues using the foreign exchange rate at December 31, 2014.

FINANCIAL RESULTS

SELECTED CONSOLIDATED FINANCIAL RESULTS

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

($millions, except per share amounts)	2014	PERCENT CHANGE	2013	PERCENT CHANGE	2012
Revenues	19,642	5%	18,657	11%	16,842
Operating Cash Flow (1)	4,158	(7%)	4,468	–%	4,451
Cash Flow (1)	3,479	(4%)	3,609	(1%)	3,643
Per Share – Diluted	4.59	(4%)	4.76	(1%)	4.80
Operating Earnings (1)	633	(46%)	1,171	35%	868
Per Share – Diluted	0.84	(46%)	1.55	36%	1.14
Net Earnings	744	12%	662	(33%)	995
Per Share – Basic	0.98	11%	0.88	(33%)	1.32
Per Share – Diluted	0.98	13%	0.87	(34%)	1.31
Total Assets	24,695	(2%)	25,224	4%	24,216
Total Long-Term Financial Liabilities (2)	5,484	(10%)	6,113	–%	6,128
Capital Investment (3)	3,051	(6%)	3,262	(3%)	3,368
Cash Dividends	805	10%	732	10%	665
Per Share	1.0648	10%	0.968	10%	0.88

(1) Non-GAAP measure defined in this MD&A.
(2) Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(3) Includes expenditures on PP&E and Exploration and Evaluation ("E&E") assets.

REVENUES

During 2014, revenues increased $985 million or five percent compared with 2013 primarily related to an increase in upstream revenues, which include the Oil Sands and Conventional segments.

($ millions)	2014 VS. 2013	2013 VS. 2012
Revenues, Comparative Year	18,657	16,842
Increase (Decrease) due to:		
Oil Sands	1,020	610
Conventional	220	177
Refining and Marketing	(48)	1,350
Corporate and Eliminations	(207)	(322)
Revenues, End of Year	19,642	18,657

Upstream revenues rose in 2014 by 19 percent primarily due to higher blended crude oil sales volumes and rising sales prices for blended crude oil and natural gas, partially offset by an increase in royalties.

Revenues generated by our Refining and Marketing segment decreased slightly as a 19 percent increase in revenues from our marketing operations was offset by a five percent decline from our refining operations. Revenues from third-party sales undertaken by the marketing group increased primarily due to higher purchased crude oil and natural gas volumes and an increase in natural gas sales prices. Refining revenues decreased due to a decline in refined product pricing consistent with lower Chicago RUL and Chicago ULSD benchmark prices and lower refined product output, partially offset by the weakening of the Canadian dollar.

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

Revenues increased in 2013 compared with 2012 primarily in our refining operations. The increases were due to higher refined product output and a weakening of the Canadian dollar. In our upstream operations, revenues increased due to higher blended crude oil sales volumes and an increase in sales prices for natural gas and blended crude oil.

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

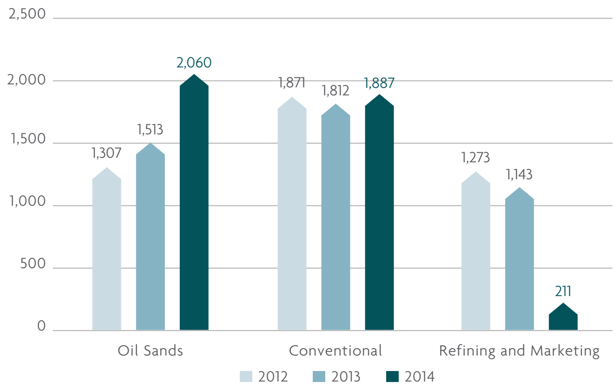
OPERATING CASH FLOW

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

($ millions)	2014	2013	2012
Revenues	20,454	19,262	17,125
(Add) Deduct:			
Purchased Product	11,767	11,004	9,506
Transportation and Blending	2,477	2,074	1,798
Operating Expenses	2,072	1,803	1,669
Production and Mineral Taxes	46	35	37
Realized (Gain) Loss on Risk Management Activities	(66)	(122)	(336)
Operating Cash Flow	4,158	4,468	4,451

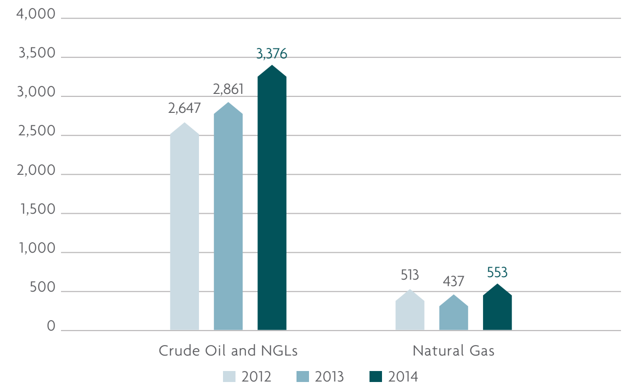
OPERATING CASH FLOW BY SEGMENT

($ millions)



UPSTREAM OPERATING CASH FLOW BY PRODUCT

($ millions)



Total Operating Cash Flow in 2014 was $4,158 million, a decline of seven percent from 2013. As highlighted in the graph below, our Operating Cash Flow decreased $310 million compared with 2013 primarily due to:

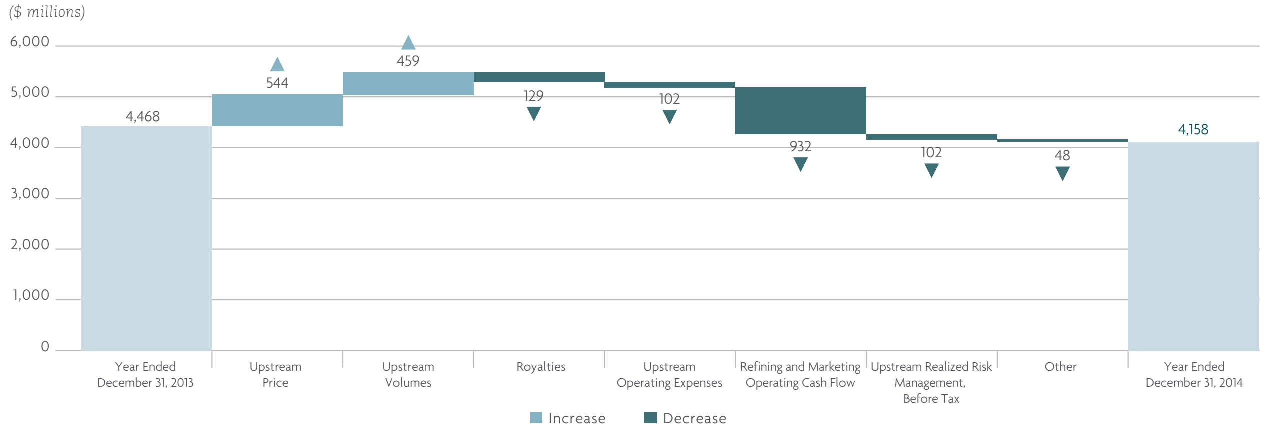
- A decline in Operating Cash Flow from Refining and Marketing as a result of a decrease in average market crack spreads, higher heavy crude oil feedstock costs relative to WTI, increased operating expenses, an inventory write-down and lower refined product output. Refining and Marketing Operating Cash Flow was also impacted by the steep decline in prices in the fourth quarter due to a time lag between the purchase of crude oil feedstock at low prices and the processing through our refineries, and our valuation of feedstock costs on a FIFO accounting basis;
- Higher royalties due to an increase in crude oil sales prices and volumes;
- An increase in crude oil operating expenses, partially due to higher crude oil production. On a per barrel basis, crude oil operating expenses decreased by $0.06 to $15.59 per barrel; and
- Realized risk management gains before tax, excluding Refining and Marketing, of $39 million compared with gains of $141 million in 2013.

The decreases were partially offset by:

- A six percent increase in our average crude oil sales price to $71.35 per barrel and a 37 percent increase in our average natural gas sales price to $4.37 per Mcf; and
- A 12 percent increase in our crude oil sales volumes.

Operating Cash Flow Variance

($ millions)



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)	2014	2013	2012
Cash From Operating Activities	**3,526**	3,539	3,420
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(135)**	(120)	(113)
Net Change in Non-Cash Working Capital	**182**	50	(110)
Cash Flow	**3,479**	3,609	3,643

In 2014, Cash Flow decreased $130 million primarily due to:

- Lower Operating Cash Flow, as discussed above; and
- A decrease in interest income as a result of receiving the remaining principal and interest due under the Partnership Contribution Receivable in December 2013.

Declines in Cash Flow were partially offset by:

- Lower finance costs as a result of the prepayment of the Partnership Contribution Payable in the first quarter of 2014 and a premium paid on the early redemption of senior unsecured notes in the third quarter of 2013;
- A decrease in current income tax, primarily due to a favourable adjustment related to prior years and a decrease in U.S. Operating Cash Flow, partially offset by an increase in Canadian taxable income; and
- A pre-exploration expense of $64 million recorded in 2013.

OPERATING EARNINGS

Operating Earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings is defined as Earnings Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, realized foreign exchange loss on the early receipt of the Partnership Contribution Receivable described below, less income taxes on Operating Earnings before tax.

In December 2013, our partner exercised its right under the FCCL Partnership Agreement to early retire the remaining principal of the Partnership Contribution Receivable. This resulted in the crystallization of realized foreign exchange losses from a stronger Canadian dollar as compared with the date when the note was originally issued. This realized foreign exchange loss has been excluded from the calculation of Operating Earnings as it is not reflective of our ongoing operations.

($ millions)	2014	2013	2012
Earnings, Before Income Tax	**1,195**	1,094	1,778
Add (Deduct):			
Unrealized Risk Management (Gain) Loss (1)	**(596)**	415	(57)
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**458**	52	(84)
Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable	**–**	146	–
(Gain) Loss on Divestiture of Assets	**(156)**	1	–
Operating Earnings, Before Income Tax	**901**	1,708	1,637
Income Tax Expense	**268**	537	769
Operating Earnings	**633**	1,171	868

(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 the Partnership Contribution Receivable and foreign exchange (gains) losses on settlement of intercompany transactions.

In 2014, Operating Earnings decreased $538 million primarily due to:

- A decrease in Cash Flow as discussed above;
- Goodwill impairment of $497 million associated with our Pelican Lake property included in the Northern Alberta cash-generating unit ("CGU");
- An increase in DD&A primarily related to higher DD&A rates at our oil sands properties, an increase in sales volumes and a PP&E impairment of $65 million; and
- An increase in exploration expense primarily related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible.

These decreases were partially offset by lower deferred income tax primarily related to a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014. The goodwill impairment charge is non-deductible for tax purposes.

NET EARNINGS

($ millions)	2014 VS. 2013	2013 VS. 2012
Net Earnings, Comparative Year	662	995
Increase (Decrease) due to:		
Operating Cash Flow (1)	(310)	17
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	1,011	(472)
Unrealized Foreign Exchange Gain (Loss)	(371)	(110)
Gain (Loss) on Divestiture of Assets	157	(1)
Expenses (2)	196	(217)
Depreciation, Depletion and Amortization	(113)	(248)
Goodwill Impairment	(497)	393
Exploration Expense	28	(46)
Income Tax Expense	(19)	351
Net Earnings, End of Year	744	662

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

Net Earnings increased 12 percent in 2014 primarily due to:

- Unrealized risk management gains before tax of $596 million (2013 – unrealized losses before tax of $415 million);
- A gain of $156 million on the sale of non-core assets; and
- The absence of a realized foreign exchange loss in 2014 related to the Partnership Contribution Receivable. In 2013, a realized foreign exchange loss of $146 million was recorded related to the receipt of the remaining principal on the Partnership Contribution Receivable as discussed above.

The increases in Net Earnings were partially offset by:

- A decline in Operating Earnings of $538 million as discussed above; and
- Non-operating unrealized foreign exchange losses of $458 million (2013 – loss of $52 million).

Net Earnings decreased $333 million in 2013 compared with 2012 primarily due to unrealized risk management losses compared with gains in 2012 and an increase in DD&A, partially offset by the absence of a goodwill impairment in 2013 compared with a goodwill impairment of $393 million recorded in 2012 in our Conventional segment.

NET CAPITAL INVESTMENT

($ millions)	2014	2013	2012
Oil Sands	**1,986**	1,885	1,697
Conventional	**840**	1,189	1,362
Refining and Marketing	**163**	107	118
Corporate and Eliminations	**62**	81	191
Capital Investment	**3,051**	3,262	3,368
Acquisitions	**18**	32	114
Divestitures	**(277)**	(283)	(76)
Net Capital Investment [1]	**2,792**	3,011	3,406

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

Oil Sands capital investment in 2014 focused primarily on the expansion phases at Foster Creek and Christina Lake, and the construction of phase A at Narrows Lake. Capital investment includes the drilling of 320 gross stratigraphic test wells.

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

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

Capital also includes spending on technology development, which plays an integral role in our business. Having a strategy focused on innovation and technology development is vital to our ability to minimize our environmental footprint and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to potentially reduce costs, enhance the recovery techniques we use to access crude oil and natural gas and improve our refining processes. In 2014, our capital investment included $101 million on technology development activities.

Capital investment in our Corporate and Eliminations segment includes spending on corporate assets, such as computer equipment, leasehold improvements and office furniture.

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

Acquisitions and Divestitures

As part of our business plan, we look for opportunities to manage our portfolio in areas where we may apply our core competencies in crude oil development.

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. In 2013, divestitures primarily included the sale of our Lower Shaunavon asset for net proceeds of $241 million.

In 2014 and 2013, we had no material acquisitions.

CAPITAL INVESTMENT DECISIONS

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

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

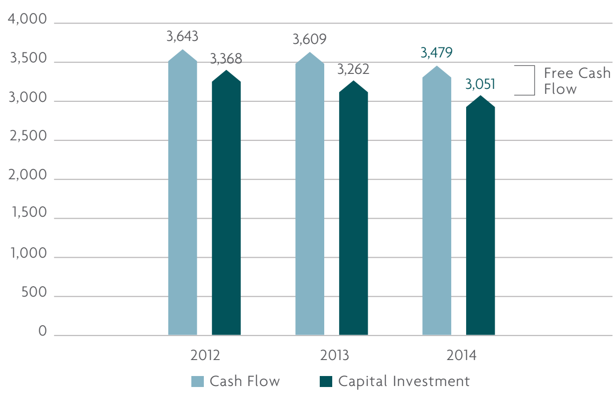
Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow. We anticipate maintaining investment grade credit ratings. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio.

Cash flow from our crude oil, natural gas and refining operations is expected to fund a portion of our cash requirements, with any remainder funded through prudent use of our balance sheet capacity and management of our asset portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

($ millions)	2014	2013	2012
Cash Flow [(1)]	**3,479**	3,609	3,643
Capital Investment (Committed and Growth)	**3,051**	3,262	3,368
Free Cash Flow [(2)]	**428**	347	275
Dividends Paid	**805**	732	665
	(377)	(385)	(390)

(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.

FREE CASH FLOW BEFORE DIVIDENDS
($ millions)



In January 2015, we revised our 2015 capital budget in order to preserve cash and maintain the strength of our balance sheet in the current low crude oil price environment. We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. Refer to the Reportable Segments section of this MD&A for more details and the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

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

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

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

(1) The Pelican Lake heavy oil operations located within the Greater Pelican Region form part of Cenovus's Conventional Oil and Gas operations.

This graphic is for illustration purposes only. Land as at December 31, 2014.

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)	2014	2013	2012
Oil Sands	4,800	3,780	3,170
Conventional	2,996	2,776	2,599
Refining and Marketing	12,658	12,706	11,356
Corporate and Eliminations	(812)	(605)	(283)
	19,642	18,657	16,842

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 that impacted our Oil Sands segment in 2014 compared with 2013 include:

- Christina Lake production increasing 40 percent, to an average of 69,023 barrels per day, with phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facility and better reservoir performance with strong base well performance and a lower SOR;
- Commencing first production at Foster Creek phase F in the third quarter of 2014. Production ramp up is expected to take approximately eighteen months;
- Foster Creek production averaging 59,172 barrels per day primarily due to improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology;
- Completing a planned turnaround at Christina Lake phases A and B and Foster Creek, with minimal impact to production. Christina Lake production volumes were processed through the phase C, D and E plant and the Foster Lake planned turnaround was smaller in scale as compared to the major planned turnaround in 2013;
- Receiving regulatory approval for phase J, a 50,000 gross barrels per day phase, at Foster Creek; a 180,000 gross barrels per day SAGD operation at our Grand Rapids project; and a 90,000 gross barrels per day SAGD project at Telephone Lake; and
- Receiving regulatory approval for expansion of the Foster Creek development area.

OIL SANDS – CRUDE OIL

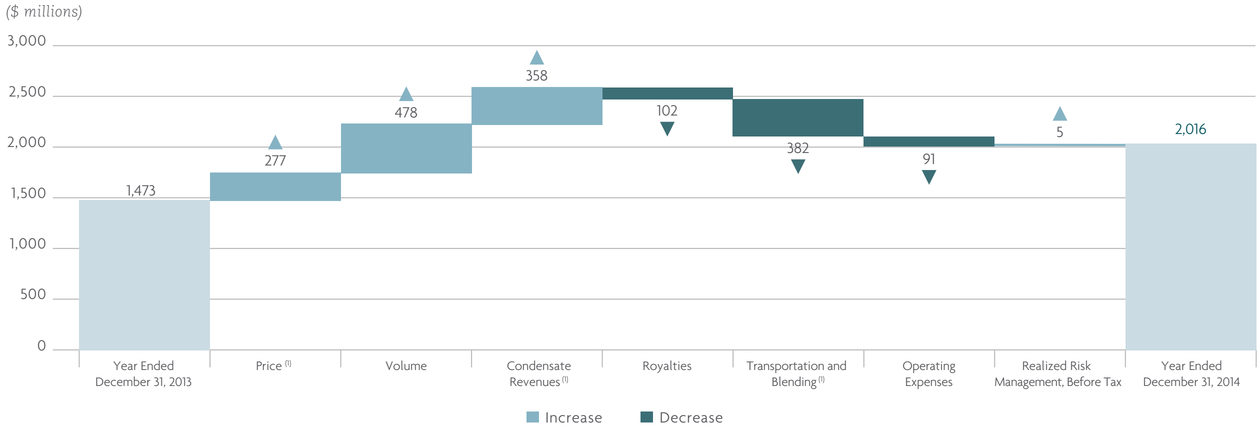
Financial and Per-unit Results

	2014		2013		2012	
($ millions, unless otherwise noted (1))		*$ per-unit*		*$ per-unit*		*$ per-unit*
Gross Sales	4,963	109	3,850	103	3,307	102
Less: Royalties	233	5	131	4	186	6
Revenues	4,730	104	3,719	99	3,121	96
Expenses						
Transportation and Blending	2,130	47	1,748	47	1,499	46
Operating	622	14	531	14	401	12
(Gain) Loss on Risk Management	(38)	(1)	(33)	(1)	(46)	(1)
Operating Cash Flow	2,016	44	1,473	39	1,267	39
Capital Investment	1,980		1,880		1,689	
Operating Cash Flow Net of Related Capital Investment	36		(407)		(422)	

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

Capital investment in excess of Operating Cash Flow in 2013 and 2012 was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

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 2014, our average oil sands crude oil sales price was $65.18 per barrel (excluding financial hedging), a 10 percent increase from 2013. This is consistent with the increase in the WCS and CDB benchmark prices and the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 38 percent, to a discount of US$3.94 per barrel (2013 – a discount of US$6.33 per barrel), primarily due to greater access to refineries that can process heavier crude oil from improved pipeline access to the U.S. Gulf Coast and increased rail takeaway capacity. In 2014, 59,266 barrels per day of Christina Lake production was sold as CDB (2013 – 42,664 barrels per day), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	2014	PERCENT CHANGE	2013	PERCENT CHANGE	2012
Foster Creek	**59,172**	**11%**	53,190	(8%)	57,833
Christina Lake	**69,023**	**40%**	49,310	55%	31,903
	128,195	**25%**	102,500	14%	89,736

Christina Lake production increased significantly as a result of phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facilities, and better reservoir performance with strong base well performance and a lower SOR. We completed a planned partial turnaround in the second quarter of 2014 that had a minimal impact on production as volumes were processed through the phase C, D and E plant. In 2013, a planned full turnaround was performed that reduced production by approximately 1,900 barrels per day.

Foster Creek production increased as a result of improved performance at our facilities, optimization efforts and increased production from wells using our Wedge Well™ technology. In 2014, we improved our downhole instrumentation, enhanced steam distribution across the field and improved how steam moves along individual wells. In addition, we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. We also achieved first production from phase F in September 2014, with ramp up expected to take approximately eighteen months. The planned turnaround in 2014, which was smaller in scale compared with the 2013 planned major turnaround, had a minimal impact on production.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it through pipelines to market. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential, the proportion of the cost of condensate recovered in 2014 increased compared with 2013.

Royalties

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

Royalties at 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)	2014	2013	2012
Foster Creek	**8.8**	5.8	11.8
Christina Lake	**7.5**	6.8	6.2

Royalties increased $102 million in 2014, primarily related to the royalty calculation at Foster Creek based on net profits that resulted in an effective royalty rate of 8.8 percent in 2014 compared with a calculation using gross revenues in 2013 (effective royalty rate – 5.8 percent), an increase in sales volumes and higher realized sales prices.

EXPENSES

Transportation and Blending

Transportation and blending costs increased $382 million or 22 percent. Blending costs rose primarily due to an increase in condensate volumes, consistent with the rise in production. In 2014, we recorded a $6 million write-down of our crude oil line fill inventory to net realizable value as a result of the decline in crude oil prices. Transportation charges increased $18 million due to a rise in production and higher volumes transported by rail, partially offset by lower sales into the U.S. market which attract higher tariffs.

Operating

Primary drivers of our operating expenses in 2014 were fuel, workforce and workover activities. While total operating expenses increased $91 million, on a per-unit basis, costs decreased to $13.66 per barrel primarily as a result of the increase in production.

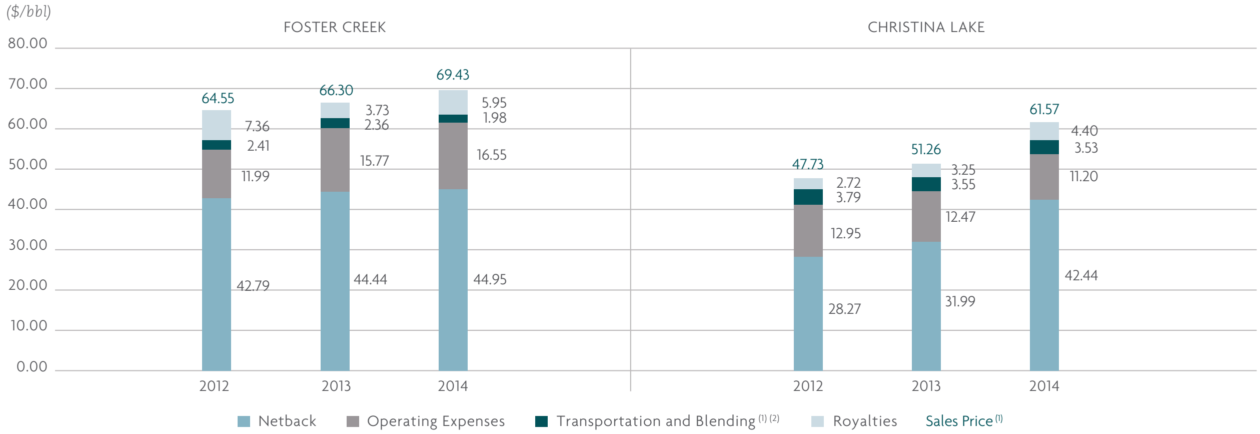
Per-unit Operating Expenses

($/bbl)	2014	PERCENT CHANGE	2013	PERCENT CHANGE	2012
Foster Creek					
Fuel	**4.46**	**55%**	2.88	42%	2.03
Non-fuel	**12.09**	**(6%)**	12.89	29%	9.96
Total	**16.55**	**5%**	15.77	32%	11.99
Christina Lake					
Fuel	**3.65**	**20%**	3.03	25%	2.42
Non-fuel	**7.55**	**(20%)**	9.44	(10%)	10.53
Total	**11.20**	**(10%)**	12.47	(4%)	12.95
Total	**13.66**	**(4%)**	14.19	15%	12.33

At Foster Creek, fuel costs continue to have a significant impact on our per-unit operating expenses, increasing $1.58 per barrel. The increase is due to higher natural gas prices and an increase in consumption resulting from a higher SOR. The increase in the SOR was due to the ramp up of Foster Creek phase F. Non-fuel operating expenses declined $0.80 per barrel, primarily due to a rise in production as a result of improved performance at our facilities.

At Christina Lake, fuel costs increased by $0.62 per barrel due to a rise in natural gas prices, partially offset by a decrease in fuel consumption on a per barrel basis. Non-fuel operating expenses decreased $1.89 per barrel, primarily due to an increase in production and a decline in fluid, waste handling and trucking costs as a result of work done to optimize chemicals used. Declines were partially offset by an increase in workover activities related to well servicing.

OPERATING NETBACKS



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate in 2014 was $42.01 per barrel (2013 – $42.41 per barrel; 2012 – $41.85 per barrel) for Foster Creek; and $45.45 per barrel (2013 – $45.25 per barrel; 2012 – $45.83 per barrel) for Christina Lake.

(2) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013 or 2012.

Risk Management

Risk management activities resulted in realized gains of $38 million (2013 – realized gains of $33 million), consistent with our contract prices exceeding average benchmark prices.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent-owned natural gas operations in Athabasca. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for 2014, net of internal usage, was 22 MMcf per day (2013 – 21 MMcf per day). Operating Cash Flow was $45 million in 2014 (2013 – $22 million), primarily due to higher natural gas sales prices.

OIL SANDS – CAPITAL INVESTMENT

($ millions)	2014	2013	2012
Foster Creek	**796**	797	735
Christina Lake	**794**	688	593
	1,590	1,485	1,328
Narrows Lake	**175**	152	44
Telephone Lake	**112**	93	138
Grand Rapids	**63**	39	65
Other [1]	**46**	116	122
Capital Investment [2]	**1,986**	1,885	1,697

(1) Includes new resource plays and Athabasca natural gas.

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

Existing Projects

Capital investment at Foster Creek in 2014 focused on expansion phases F, G and H, offsite facility work related to phases G and H, drilling of sustaining wells including the use of our Wedge Well™ technology, and operational improvement projects. Costs related to the expansion of phases F, G and H increased more than expected as a result of changes to the phases that we believe will result in better long-term plant reliability and production efficiency. These include improvements to the plant safety systems, completion designs and the incorporation of recent regulatory changes. Capital investment remained relatively consistent year over year due to higher spending on offsite facilities, drilling and completions on well pairs and wells using our Wedge Well™ technology, offset by a decrease in spending on plant facilities and operational improvement projects.

In 2014, Christina Lake capital investment focused on expansion phases F and G, phase E well pad and facility construction, and sustaining well programs including the use of our Wedge Well™ technology. Capital investment increased due to sustaining well programs including our Wedge Well™ technology, and phases F and G plant engineering, procurement and construction, partially offset by reduced spending on phase E plant construction.

Capital investment at Narrows Lake increased as spending continued on phase A engineering, procurement and plant construction. Spending on phase A plant construction started in the third quarter of 2013.

Emerging Projects

In 2014, Telephone Lake capital investment was primarily focused on preliminary engineering work on the central processing facility, costs related to the dewatering pilot project and the drilling of stratigraphic test wells. Capital spending increased as a result of our ability to have a summer stratigraphic well program due to our SkyStrat™ drilling rig, which focused on acreage acquired in 2014 adjacent to the central processing facility site.

Capital investment at Grand Rapids in 2014 was primarily focused on costs related to the pilot project and the drilling of stratigraphic test wells. Capital investment increased due to the dismantling and removal of the Joslyn facility which we plan to install at Grand Rapids, partially offset by a decline in costs related to our 2014 winter program.

DRILLING ACTIVITY

	GROSS STRATIGRAPHIC TEST WELLS (1)			GROSS PRODUCTION WELLS (2) (3)		
	2014	2013	2012	**2014**	2013	2012
Foster Creek	**165**	112	141	**63**	56	28
Christina Lake	**57**	74	98	**67**	35	32
	222	186	239	**130**	91	60
Narrows Lake	**22**	26	42	**–**	–	–
Telephone Lake	**45**	28	29	**–**	–	–
Grand Rapids	**10**	3	62	**–**	–	1
Other	**21**	96	96	**–**	–	–
	320	339	468	**130**	91	61

(1) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In 2014, we drilled 14 wells (2013 – 24 wells; 2012 – 15 wells).
(2) SAGD well pairs are counted as a single producing well.
(3) Includes wells drilled using our Wedge Well™ technology.
(4) In addition to the drilling activity above, we drilled three gross service wells in 2014 (2013 – 27 gross service wells; 2012 – 34 gross service wells).

Stratigraphic test wells were drilled at Foster Creek, Christina Lake and Narrows Lake to help identify well pad locations for the expansion phases under construction, add contingent resources and increase well density per section for future expansion phases. Other stratigraphic test wells were drilled to continue gathering data on the quality of our projects and to support regulatory applications for project approval.

FUTURE CAPITAL INVESTMENT

As a result of the current low crude oil price environment, we have decided to slow capital activities in 2015 in order to preserve cash and maintain the strength of our balance sheet. Readers can also review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. In addition, we expect to see reductions in demand for labour, service and materials which should create potential opportunities for us to drive improvements in our cost structure. Our capital budget has a degree of flexibility and as such we will continue to assess spending plans on a regular basis and make adjustments, if required.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2015 is forecast to be between $550 million and $600 million and we plan to focus on our existing operations as well as expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day. First production from phase G is anticipated in the first half of 2016. Spending related to phase H, with an initial design capacity of 30,000 barrels per day, has been deferred in response to the low crude oil price environment, pushing expected start up to beyond 2017. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrel per day phase.

Christina Lake is producing from phases A through E. Capital investment in 2015 is forecast to be between $650 million and $700 million and we plan to focus on activities necessary for our existing operations, expansion phase F and the phase C, D and E optimization program. Expansion work on phase F, including cogeneration, is expected to continue as planned. We expect to add production capacity of 50,000 gross barrels per day from phase F in the second half of 2016. The phase C, D and E optimization program is expected to add production capacity of 22,000 gross barrels per day in the fourth quarter of 2015. Spending related to phase G, with an initial design capacity of 50,000 gross barrels per day, has been deferred in response to the low crude oil price environment, pushing expected start up to beyond 2017. We submitted a joint application and environmental impact assessment to regulators in March 2013 for the phase H expansion, a 50,000 gross barrel per day phase, for which we expect to receive regulatory approval in the first half of 2015.

Capital investment at Narrows Lake is forecast to be between $30 million and $40 million in 2015. In 2015, we plan to focus our capital investment on detailed engineering and procurement. We have suspended new construction spending on phase A until crude oil prices recover. In 2012, we received regulatory approval for Narrows Lake phases A, B and C, for 130,000 gross barrels per day, and partner approval for phase A, a 45,000 gross barrel per day phase.

Emerging Projects

Two of our emerging projects are Telephone Lake and Grand Rapids. Capital investment for our new resource plays is forecast to be between $90 million and $100 million in 2015 and we plan to focus on continuing the pilot project at Grand Rapids and the dismantling, removal and reconstruction of the Joslyn facility as well as front-end engineering at Telephone Lake. At Grand Rapids, we are planning on drilling a third pilot well pair in the first quarter of 2015 and plan to continue operating the SAGD pilot project to gather additional information on the reservoir.

DD&A

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

In 2014, Oil Sands DD&A increased $179 million. The increases were due to higher DD&A rates for both of our properties from additional expenditures and a rise in future development costs associated with total proved reserves, and an increase in sales volumes.

CONVENTIONAL

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

We own the mineral rights on approximately 70 percent or 4.5 million net acres of our conventional lands (fee lands), of which 2.5 million acres are developed. Production from fee lands comprises approximately 50 percent of our total conventional production. Fee lands where we have maintained working interest production are subject to mineral tax, which is generally lower than the royalties paid to the government or other mineral interest owners. Of the 4.5 million net acres of fee land, we lease over 2.0 million acres to third parties, which may result in royalty income. In 2014, we had approximately 7,600 barrels of oil equivalent per day of royalty interest production from fee lands which resulted in Operating Cash Flow of approximately $150 million.

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

Significant developments that impacted our Conventional segment in 2014 compared with 2013 include:

- Crude oil production averaging 75,298 barrels per day, decreasing two percent. Increased production from successful horizontal well performance in southern Alberta and slightly higher production at Pelican Lake, was more than offset by expected natural declines and the sale of non-core assets;
- Generating Operating Cash Flow net of capital investment of $1,047 million, an increase of 68 percent; and
- Recording goodwill impairment of $497 million primarily due to declines in crude oil prices and a slowing down of the Pelican Lake development plan, a PP&E impairment of $65 million related to assets for which we do not believe the carrying value can be recovered, and an exploration expense of $82 million related to certain tight oil exploration assets deemed not to be commercially viable and technically feasible.

In September 2014, we completed the sale of certain of our Wainwright assets in Alberta for net proceeds of $234 million. A gain on disposition of $137 million was recorded on the sale. Prior to the sale, crude oil production from these assets was 2,775 barrels per day for the first three quarters in 2014 (year ended December 31, 2013 – 2,566 barrels per day).

In April 2014, we sold certain of our Bakken assets in southeastern Saskatchewan for net proceeds of $35 million. A gain on disposition of $16 million was recorded on the sale. Prior to the sale, crude oil production from these Bakken assets was 396 barrels per day in the first quarter of 2014 (year ended December 31, 2013 – 562 barrels per day).

In both the Wainwright and Bakken asset dispositions, we retained ownership of mineral interests in the applicable fee lands and receive a royalty on current and future production.

In July 2013, we sold our Lower Shaunavon asset for net proceeds of $241 million. Production averaged 4,236 barrels per day in the first half of 2013.

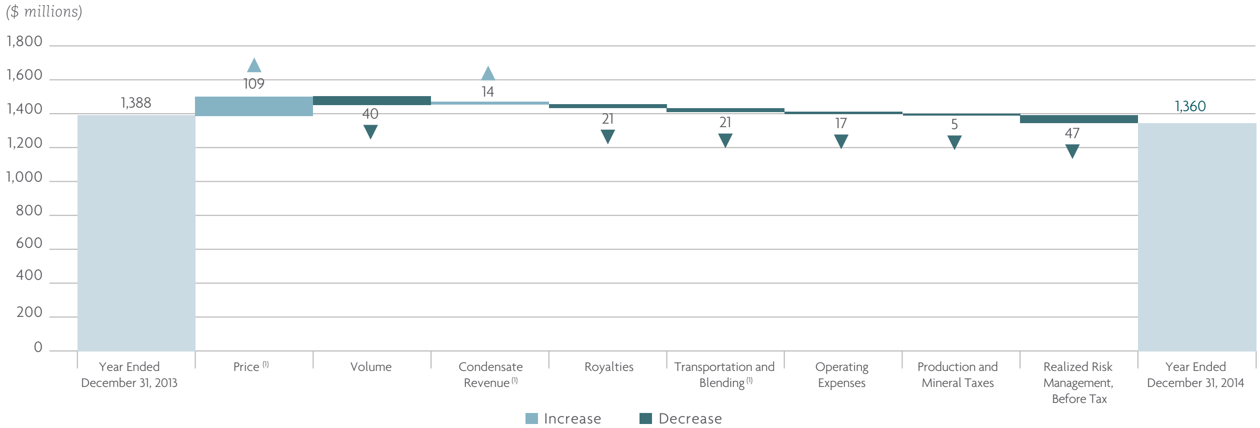
CONVENTIONAL – CRUDE OIL

Financial and Per-unit Results

	2014		2013		2012	
($ millions, unless otherwise noted [1])		*$ per-unit*		*$ per-unit*		*$ per-unit*
Gross Sales	2,456	90	2,373	85	2,289	82
Less: Royalties	217	8	196	7	195	7
Revenues	2,239	82	2,177	78	2,094	75
Expenses						
Transportation and Blending	326	12	305	11	278	10
Operating	512	19	495	18	441	16
Production and Mineral Taxes	37	1	32	1	34	1
(Gain) Loss on Risk Management	4	–	(43)	(2)	(39)	(1)
Operating Cash Flow	1,360	50	1,388	50	1,380	49
Capital Investment	812		1,167		1,319	
Operating Cash Flow Net of Related Capital Investment	548		221		61	

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

OPERATING CASH FLOW VARIANCE



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

REVENUES

Pricing

Our average crude oil sales price increased five percent to $81.62 per barrel (excluding financial hedging), consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

(barrels per day)	2014	PERCENT CHANGE	2013	PERCENT CHANGE	2012
Pelican Lake	**24,924**	**3%**	24,254	8%	22,552
Other Heavy Oil	**14,622**	**(9%)**	15,991	–%	16,015
Total Heavy Oil	**39,546**	**(2%)**	40,245	4%	38,567
Light and Medium Oil	**34,531**	**(3%)**	35,467	(2%)	36,071
NGLs	**1,221**	**15%**	1,063	3%	1,029
	75,298	**(2%)**	76,775	1%	75,667

Increased production from successful horizontal well performance in southern Alberta and a slight increase in production at Pelican Lake was more than offset by expected natural declines and the divestiture of non-core assets. Higher production at Pelican Lake, related to an increased response from the polymer flood program and additional infill wells coming on stream was partially offset by a planned turnaround.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential, the proportion of the cost of condensate recovered increased.

Royalties

Royalties increased $21 million primarily due to higher realized sales prices, partially offset by a decline in sales volumes. In 2014, the effective crude oil royalty rate for our Conventional properties was 10.1 percent (2013 – 9.5 percent).

Approximately 50 percent of our production is not subject to royalties, rather is subject to mineral tax which is generally lower than the royalties paid to the government or other mineral interest owners. In 2014, production and mineral taxes increased, consistent with the rise in crude oil prices for the full year.

Royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. In 2014 and 2013, the Pelican Lake royalty calculation was based on gross revenues.

EXPENSES

Transportation and Blending

Transportation and blending costs increased $21 million. Blending costs rose primarily due to an increase in condensate volumes and higher condensate prices. In 2014, we recorded a $12 million write-down of our crude oil line fill inventory to net realizable value as a result of the decline in crude oil prices as at year end. Transportation charges were $5 million lower due to a decrease in volumes moved by rail and a decline in sales volumes.

Operating

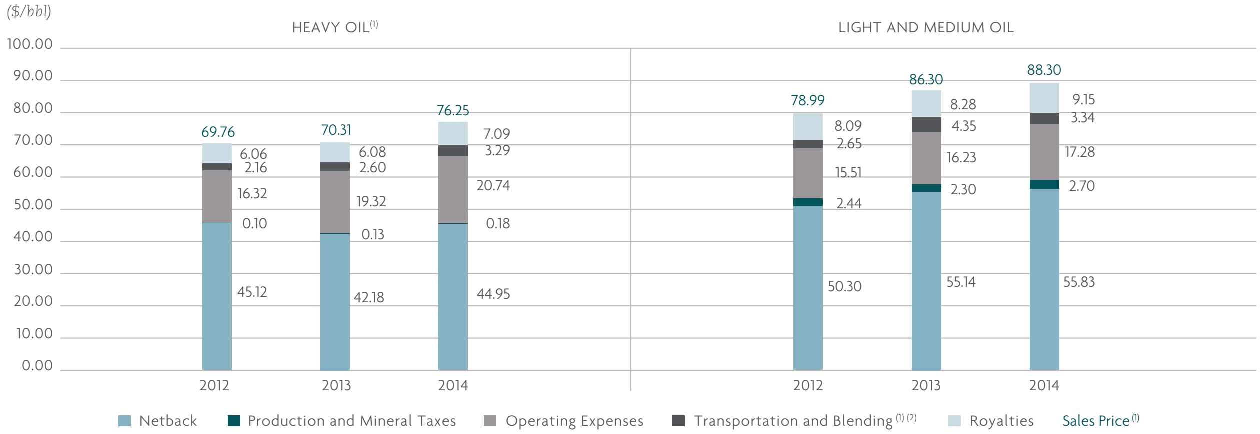
Primary drivers of our operating expenses in 2014 were workover activities, workforce costs, repairs and maintenance, electricity, and chemical consumption. Operating expenses rose $17 million to $18.81 per barrel.

Operating expenses increased $1.20 per barrel, primarily due to:

- Higher chemical costs associated with a rise in the price of polymer and an increase in polymer consumption. Operating expenses include polymer as it is consumed when it is injected into the reservoir as part of the waterflood process; and
- A rise in fluid, waste handling and trucking costs associated with wells drilled in 2014.

Increased crude oil operating expenses were partially offset by declines related to the sale of non-core assets, in addition to lower electricity costs as a result of a decline in electricity prices.

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 $15.71 per barrel (2013 – $14.60 per barrel; 2012 – $14.66 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. There was no product inventory write-down recorded in 2013 or 2012.

Risk Management

Risk management activities in 2014 resulted in realized losses of $4 million (2013 – realized gains of $43 million), consistent with average benchmark prices exceeding our contract prices.

CONVENTIONAL – NATURAL GAS

Financial Results

($ millions)	2014	2013	2012
Gross Sales	744	594	498
Less: Royalties	12	8	6
Revenues	732	586	492
Expenses			
Transportation and Blending	20	20	19
Operating	200	209	217
Production and Mineral Taxes	9	3	3
(Gain) Loss on Risk Management	(5)	(61)	(229)
Operating Cash Flow	508	415	482
Capital Investment	28	22	43
Operating Cash Flow Net of Related Capital Investment	480	393	439

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

REVENUES

Pricing

Our average natural gas sales price increased $1.17 per Mcf to $4.37 per Mcf, consistent with the rise in the AECO benchmark price.

Production

Production decreased eight percent to 466 MMcf per day primarily due to expected natural declines.

Royalties

Royalties increased slightly as higher prices more than offset the impact of production declines. The average royalty rate in 2014 was 1.6 percent (2013 – 1.4 percent). Most of our natural gas production is located on fee lands where we hold mineral rights, which results in mineral tax being recorded within production and mineral taxes. In 2014, production and mineral taxes increased, consistent with the rise in natural gas prices, partially offset by the decline in volume.

EXPENSES

Transportation

Transportation costs remained consistent as a result of lower production volumes, partially offset by higher pipeline rates.

Operating

In 2014, our operating expenses were primarily composed of property taxes and lease costs, workforce and repairs and maintenance. Operating expenses decreased $9 million primarily due to natural production declines and decreases in electricity costs, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities resulted in realized gains of $5 million (2013 – realized gains of $61 million), consistent with our contract prices exceeding average benchmark prices.

CONVENTIONAL – CAPITAL INVESTMENT [(1)]

($ millions)	2014	2013	2012
Pelican Lake	**246**	463	514
Other Heavy Oil	**92**	135	126
Light and Medium Oil	**474**	569	679
Natural Gas	**28**	22	43
	840	1,189	1,362

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

Capital investment in 2014 was primarily composed of spending on tight oil development and facilities work. At Pelican Lake, capital investment focused on infill drilling, maintenance capital and facility upgrades associated with the expansion of the polymer flood. Spending on natural gas activities continues to be managed in response to the natural gas price environment and to focus on well recompletions. The decline in capital investment at Pelican Lake reflects our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program.

Conventional Drilling Activity

(net wells, unless otherwise stated)	2014	2013	2012
Crude Oil	**126**	212	352
Recompletions	**803**	751	977
Gross Stratigraphic Test Wells	**30**	54	19
Other [(1)]	**40**	77	115

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

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

FUTURE CAPITAL INVESTMENT

In 2015, crude oil capital investment is forecast to be between $200 million and $215 million with spending mainly focused on maintenance capital and spending for our CO_2 facility at Weyburn. As a result of the current low crude oil price environment, our 2015 capital spending reflects the suspension of the majority of our 2015 drilling program in southern Alberta and Saskatchewan.

DD&A, GOODWILL IMPAIRMENT AND EXPLORATION EXPENSE

DD&A

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

Conventional DD&A decreased $88 million in 2014. The decrease was primarily due to a decline in sales volumes and lower DD&A rates from a decrease in expenditures and the non-core asset sales.

In the fourth quarter of 2014, an impairment loss of $52 million was recorded related to the carrying amount of purchased equipment that will now not be used in its intended location, and we do not believe the carrying value can be recovered through a sale. In the second quarter of 2014, we recorded an impairment loss related to a minor natural gas property that was shut-in and abandonment commenced. 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 included in our Northern Alberta CGU. The impairment was primarily due to a decline in crude oil prices and a slowing down of the Pelican Lake development plan. There was no goodwill impairment in 2013.

Exploration Expense

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

In 2014, $82 million (2013 – $50 million) of previously capitalized E&E costs, related to certain conventional tight oil exploration assets, were deemed not to be commercially viable and technically feasible and were recorded as exploration expense.

As part of our business plan, we look for opportunities to enhance our portfolio in areas where we may apply our core competencies in crude oil development. Costs incurred prior to obtaining the legal right to explore (pre-exploration) are expensed. In 2013, as a result of our evaluation of crude oil exploration opportunities, $64 million of pre-exploration expense was recorded. There was no pre-exploration expense recorded in 2014.

REFINING AND MARKETING

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

The weakening of the Canadian dollar by seven percent in 2014 as compared with 2013 had a positive impact of approximately $60 million on our refining gross margin.

Significant developments that impacted our Refining and Marketing segment in 2014 compared with 2013 include:

- Crude oil runs and refined product output decreasing four percent as a result of an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery;
- Operating Cash Flow declining 82 percent to $211 million primarily due to lower average market crack spreads, an increase in heavy crude oil feedstock costs, higher operating expenses, an inventory write-down of $113 million primarily related to the significant decline in refined product prices, and a decrease in refined product output; and
- In the fourth quarter of 2014, the rapidly declining commodity price environment resulted in the cost of feedstock processed being higher than the refined product pricing we realized in December.

REFINERY OPERATIONS (1)

	2014	2013	2012
Crude Oil Capacity (2) *(Mbbls/d)*	460	457	452
Crude Oil Runs *(Mbbls/d)*	423	442	412
Heavy Crude Oil	199	222	198
Light/Medium	224	220	214
Refined Products *(Mbbls/d)*	445	463	433
Gasoline	231	232	216
Distillate	137	144	138
Other	77	87	79
Crude Utilization *(percent)*	92	97	91

(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 in 2013, increased effective January 1, 2014.

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 continues to benefit our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In 2014, an unplanned coker outage at our Borger refinery and a planned turnaround at our Wood River refinery reduced crude oil runs, refined product output and crude utilization when compared with 2013. In 2013, an unplanned hydrocracker outage at our Wood River refinery negatively impacted volumes, however to a lesser extent.

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

FINANCIAL RESULTS

($ millions)	2014	2013	2012
Revenues	12,658	12,706	11,356
Purchased Product	11,767	11,004	9,506
Gross Margin	891	1,702	1,850
Expenses			
Operating	707	540	581
(Gain) Loss on Risk Management	(27)	19	(4)
Operating Cash Flow	211	1,143	1,273
Capital Investment	163	107	118
Operating Cash Flow Net of Related Capital Investment	48	1,036	1,155

Gross Margin

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

In the fourth quarter of 2014, we experienced a rapidly declining commodity price environment. This resulted in the cost of feedstock processed being significantly higher than the refined product pricing we realized in December due to the time lag discussed above and the valuation of our feedstock costs on a FIFO accounting basis.

In 2014, the decrease in gross margin was primarily due to:

- Lower average market crack spreads which decreased by approximately 20 percent, consistent with the narrowing of the Brent-WTI differential;
- Higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential;
- An inventory write-down of $113 million primarily related to our refined product and feedstock inventory, consistent with the decline in benchmark prices; and
- A decline in refined product output by four percent as discussed above.

Our refineries do not blend renewable fuels into the motor fuel products we produce, so consequently we are obligated to purchase Renewable Identification Numbers ("RINs"). In 2014, the cost of our RINs was $123 million (2013 – $153 million). These decreases are consistent with the decline in the ethanol RINs benchmark price. This cost remains a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating expenses in 2014 were maintenance, labour, utilities and supplies. Operating expenses increased 31 percent primarily due to higher planned turnaround and maintenance activities, an increase in utility costs resulting from a rise in natural gas costs and a weaker Canadian dollar.

REFINING AND MARKETING – CAPITAL INVESTMENT

($ millions)	2014	2013	2012
Wood River Refinery	101	64	54
Borger Refinery	61	42	64
Marketing	1	1	–
	163	107	118

Capital expenditures in 2014 focused on capital maintenance and refinery reliability and safety projects. In the first quarter of 2014, we and our partner sanctioned the Wood River debottleneck project. We are currently awaiting permit approval, which is anticipated in the first half of 2015, and planned start-up is anticipated in 2016.

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

DD&A

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased $18 million primarily due to the change in the U.S./Canadian dollar exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and the unrealized mark-to-market gains and losses on the long-term power purchase contract. In 2014, our risk management activities resulted in $596 million of unrealized gains, before tax (2013 – $415 million of unrealized losses, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

($ millions)	2014	2013	2012
General and Administrative	358	349	350
Finance Costs	445	529	455
Interest Income	(33)	(96)	(109)
Foreign Exchange (Gain) Loss, Net	411	208	(20)
Research Costs	15	24	15
(Gain) Loss on Divestiture of Assets	(156)	1	–
Other (Income) Loss, Net	(4)	2	(5)
	1,036	1,017	686

Expenses

GENERAL AND ADMINISTRATIVE

Primary drivers of our general and administrative expenses in 2014 were workforce, office rent and information technology costs. General and administrative expenses increased $9 million primarily due to higher staffing costs.

FINANCE COSTS

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. Finance costs decreased $84 million in 2014. The decrease was primarily due to lower interest incurred on the Partnership Contribution Payable as we exercised our right to prepay in the first quarter of 2014, and the recording of a US$32 million premium on the early redemption of senior unsecured notes in the third quarter of 2013, partially offset by higher unwinding of the discount on decommissioning liabilities and a weakening of the Canadian dollar.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable was 5.0 percent (2013 – 5.2 percent).

INTEREST INCOME

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. In December 2013, the balance of the Partnership Contribution Receivable was received therefore no related interest income was earned in 2014.

FOREIGN EXCHANGE

($ millions)	2014	2013	2012
Unrealized Foreign Exchange (Gain) Loss	411	40	(70)
Realized Foreign Exchange (Gain) Loss	–	168	50
	411	208	(20)

The majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at December 31, 2014. In addition, unrealized foreign exchange losses were lower in 2013 as a result of the reversal of previously recognized unrealized losses on the U.S. dollar Partnership Contribution Receivable.

In December 2013, we received the remaining principal of the Partnership Contribution Receivable resulting in the recognition of a realized foreign exchange loss of $146 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 2014 was $83 million (2013 – $79 million).

(GAIN) LOSS ON DIVESTITURE OF ASSETS

Divestitures in 2014 primarily included the sale of non-core assets for net proceeds of $269 million resulting in a gain of $153 million.

INCOME TAX EXPENSE

($ millions)	2014	2013	2012
Current Tax			
Canada	94	143	188
United States	(2)	45	121
Total Current Tax	92	188	309
Deferred Tax	359	244	474
	451	432	783

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

($ millions, except percent amounts)	2014	2013	2012
Earnings Before Income Tax	1,195	1,094	1,778
Canadian Statutory Rate	25.2%	25.2%	25.2%
Expected Income Tax	301	276	448
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	(43)	87	119
Non-deductible Stock-Based Compensation	13	10	10
Foreign Exchange Gains (Losses) not Included in Net Earnings	(13)	19	14
Non-taxable Capital (Gains) Losses	124	31	(7)
Derecognition (Recognition) of Capital Losses	(9)	15	(22)
Adjustments Arising From Prior Year Tax Filings	(16)	(13)	33
Withholding Tax on Foreign Dividend	–	–	68
Goodwill Impairment	125	–	99
Other	(31)	7	21
Total Tax	451	432	783
Effective Tax Rate	37.7%	39.5%	44.0%

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate. There are usually a number of tax matters under review 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.

The 2014 provision for income tax includes the effect of a favourable adjustment to current tax related to prior years, which was mostly offset by increased deferred tax and therefore had a minimal impact on total income tax. Current income tax decreased $96 million primarily due to the favourable adjustment related to prior years and lower U.S. Operating Cash Flow, partially offset by an increase in Canadian taxable income. Deferred income tax increased $115 million due to an unrealized risk management gain compared with a loss in the prior year, an increase in Canadian timing differences arising from increased Oil Sands income and the effect of the favourable adjustment to current tax related to prior years, partially offset by a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes for the year. 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.

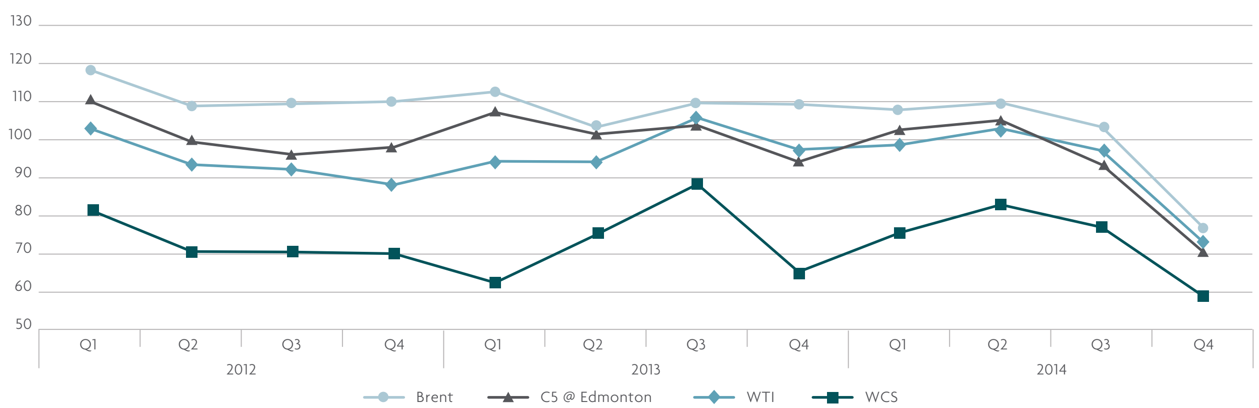
The decrease in our effective tax rate when compared with 2013 is primarily due to a decrease in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction, partially offset by the non-deductible charge for a goodwill impairment and non-deductible foreign exchange losses. In 2014, the U.S. statutory rate was 38.1 percent (2013 – 38.5 percent).

QUARTERLY RESULTS

A substantial downward shift in the commodity price environment occurred in the fourth quarter of 2014 with declining crude oil and refining benchmark prices impacting on our fourth quarter financial results. The Brent, WTI and WCS benchmark prices at December 31, 2014 decreased 39 percent, 42 percent and 50 percent, respectively, compared with September 30, 2014. The average WTI and WCS benchmark prices declined US$24.31 per barrel and US$6.35 per barrel in the fourth quarter of 2014 compared with 2013. Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices.

CRUDE OIL BENCHMARKS

(average US$/bbl)



($ millions, except per share amounts or where otherwise indicated)	Q4 2014	Q3 2014	Q2 2014	Q1 2014	Q4 2013	Q3 2013	Q2 2013	Q1 2013	Q4 2012
Production Volumes									
Crude Oil *(bbls/d)*	216,177	199,089	201,688	196,854	188,743	176,938	171,127	180,225	177,646
Natural Gas *(MMcf/d)*	479	489	507	476	514	523	536	545	566
Refinery Operations									
Crude Oil Runs *(Mbbls/d)*	420	407	466	400	447	464	439	416	311
Refined Products *(Mbbls/d)*	442	429	489	420	469	487	457	439	330
Revenues	4,238	4,970	5,422	5,012	4,747	5,075	4,516	4,319	3,724
Operating Cash Flow (1)	539	1,154	1,296	1,169	976	1,153	1,125	1,214	966
Cash Flow (1)	401	985	1,189	904	835	932	871	971	697
Per Share – Diluted	0.53	1.30	1.57	1.19	1.10	1.23	1.15	1.28	0.92
Operating Earnings (Loss) (1)	(590)	372	473	378	212	313	255	391	(188)
Per Share – Diluted	(0.78)	0.49	0.62	0.50	0.28	0.41	0.34	0.52	(0.25)
Net Earnings (Loss)	(472)	354	615	247	(58)	370	179	171	(117)
Per Share – Basic	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24	0.23	(0.15)
Per Share – Diluted	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24	0.23	(0.15)
Capital Investment (2)	786	750	686	829	898	743	706	915	978
Cash Dividends	201	201	201	202	183	182	183	184	167
Per Share	0.2662	0.2662	0.2662	0.2662	0.242	0.242	0.242	0.242	0.22

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

FOURTH QUARTER 2014 RESULTS AS COMPARED WITH THE FOURTH QUARTER 2013

Production Volumes

Total crude oil production rose 15 percent primarily due to higher production at Foster Creek and Christina Lake. Foster Creek production averaged 68,377 barrels per day, an increase of 30 percent, due to improved performance, optimization efforts, increased production from wells using our Wedge Well™ technology, and first production from phase F in September 2014. Christina Lake production averaged 73,836 barrels per day, an increase of 20 percent, due to phase E reaching nameplate production capacity in the second quarter of 2014, improved performance at our facilities and better reservoir performance.

Natural gas production in the fourth quarter of 2014 decreased seven percent as expected. We continued to focus natural gas 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 and refined product output decreased as a result of a planned turnaround at our Wood River refinery.

Revenue

Revenues decreased $509 million or 11 percent primarily due to:

- A decline in Refining and Marketing revenues of $450 million largely due a decrease in refined product prices consistent with a 19 percent decline in average refined product benchmark prices, and lower refined product output; and
- Our average crude oil sales price (excluding financial hedging) decreasing seven percent to $55.02 per barrel.

The decreases to revenues were partially offset by:

- Crude oil sales volume increasing four percent;
- An increase in condensate volumes, consistent with higher production; and
- A rise in natural gas sales prices (excluding financial hedging) of 21 percent to $3.89 per Mcf.

Operating Cash Flow

Operating Cash Flow decreased $437 million, or 45 percent. Upstream Operating Cash Flow increased four percent due to realized risk management gains of $133 million (2013 – realized risk management gains of $67 million), higher crude oil sales volumes and a decline in crude oil operating expenses of $22 million or $1.81 per barrel, partially offset by lower crude oil sales prices.

Refining and Marketing Operating Cash Flow declined significantly from $151 million in 2013 to a loss of $322 million in 2014. The decrease was due to higher heavy crude oil feedstock costs relative to WTI, lower refined product output, an inventory write-down and an increase in operating expenses, partially offset by higher average market crack spreads. In the fourth quarter, due to the rapid decline in crude oil and refining benchmark prices, our costs of feedstock processed, determined on a FIFO basis, was higher than the refined product price that we realized. This is due to the time lag between when we purchase crude oil feedstock and when it is processed through our refineries, which is approximately one to two months.

Cash Flow

Cash Flow decreased $434 million or 52 percent in the fourth quarter of 2014 primarily due to the decline in Operating Cash Flow discussed above and lower interest income, partially offset by lower finance costs and a current income tax recovery related to a decrease in U.S. Operating Cash Flow compared to an expense in 2013.

Operating Earnings (Loss)

Operating Earnings decreased $802 million in the fourth quarter of 2014 compared with the same period in 2013. The decline was due to a goodwill impairment, lower Cash Flow as discussed above, an increase in exploration expense and higher DD&A, partially offset by a deferred income tax recovery in 2014 compared to an expense in the prior year. The deferred income tax recovery was primarily related to a reduction in the utilization of U.S. tax losses as a result of a decline in U.S. Operating Cash Flow in 2014.

Net Earnings (Loss)

In the fourth quarter of 2014, our net loss was $472 million, compared with a net loss of $58 million in the same period last year. Our net loss increased $414 million primarily due to a decrease in Operating Earnings as discussed above and non-operating foreign exchange losses compared with gains in 2013, partially offset by unrealized risk management gains of $416 million compared with losses of $219 million in the fourth quarter of 2013.

Capital Investment

Capital investment in the fourth quarter of 2014 was $786 million, a decrease of $112 million from the same period in 2013 primarily due to declines in spending in our Conventional segment mostly related to a decrease at Pelican Lake. The decline in spending at Pelican Lake reflects our decision to align spending with the more moderate production ramp up associated with the results of the polymer flood program. The fourth quarter capital investment was focused on the development of our expansion phases, drilling of sustaining wells and operational improvement projects at Foster Creek and Christina Lake.

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. Our AIF for the year ended December 31, 2014, contains additional information with respect to the evaluation and reporting of our reserves and resources in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101").

Developments in 2014 compared with 2013 include:

- Proved bitumen reserves increasing seven percent and proved plus probable bitumen reserves rising 30 percent due to:
  - Christina Lake proved reserves increasing 44 million barrels due to improved reservoir performance and proved plus probable reserves rising 446 million barrels due to area expansion and improved reservoir performance; and
  - Foster Creek proved reserves increasing 77 million barrels and proved plus probable reserves rising 273 million barrels as a result of receiving regulatory approval for expansion of the development area.
- Both heavy oil proved reserves and proved plus probable heavy oil reserves declining 13 percent. The decrease was due to the deferral of drilling at Pelican Lake and the sale of certain of our Wainwright assets, partially offset by the Elk Point development in the Wainwright area.
- Light and medium crude oil and NGLs proved reserves increasing four percent and proved plus probable reserves rising one percent as a result of the expansion of the CO_2 flood area at Weyburn.
- Natural gas proved reserves declining eight percent and proved plus probable reserves decreasing nine percent as additions and improved performance were more than offset by reductions due to production.

- Bitumen best estimate economic contingent resources decreasing 0.5 billion barrels or five percent and bitumen best estimate prospective resources staying consistent at 7.5 billion barrels. Factors impacting the results include:
  - Converting 0.8 billion barrels of contingent resources to proved and probable reserves at Christina Lake and Foster Creek; and
  - Conversion of prospective resources to contingent resources through stratigraphic drilling being offset by increases to mapped reservoir volumes at Grand Rapids.

The reserves and resources data that follows is presented as at December 31, 2014 using McDaniel & Associates Consultants Ltd. ("McDaniel's") January 1, 2015 forecast prices and costs. Comparative information as at December 31, 2013 uses McDaniel's January 1, 2014 forecast prices and costs. We hold significant fee title rights which generate production for Cenovus from third parties leasing those lands. The before royalty volumes, as follows, do not include reserves associated with this production.

RESERVES

	BITUMEN (MMbbls)		HEAVY OIL (MMbbls)		LIGHT AND MEDIUM OIL & NGLs (MMbbls)		NATURAL GAS & CBM (Bcf)	
As at December 31, (before royalties)	2014	2013	2014	2013	2014	2013	2014	2013
Proved	1,970	1,846	156	179	120	115	796	865
Probable	1,330	683	123	140	46	50	260	300
Proved plus Probable	3,300	2,529	279	319	166	165	1,056	1,165

RECONCILIATION OF PROVED RESERVES

(before royalties)	BITUMEN (MMbbls)	HEAVY OIL (MMbbls)	LIGHT & MEDIUM OIL & NGLs (MMbbls)	NATURAL GAS & CBM (Bcf)
December 31, 2013	1,846	179	115	865
Extensions and Improved Recovery	108	14	17	23
Discoveries	–	–	–	–
Technical Revisions	63	(13)	1	98
Economic Factors	–	–	–	(12)
Acquisitions	–	–	–	2
Dispositions	–	(10)	(1)	(5)
Production [(1)]	(47)	(14)	(12)	(175)
December 31, 2014	1,970	156	120	796
Year Over Year Change	124	(23)	5	(69)
	7%	(13%)	4%	(8%)

(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, 2013	683	140	50	300
Extensions and Improved Recovery	648	7	–	13
Discoveries	–	–	–	–
Technical Revisions	(1)	(21)	(3)	(47)
Economic Factors	–	–	–	(5)
Acquisitions	–	–	–	–
Dispositions	–	(3)	(1)	(1)
Production	–	–	–	–
December 31, 2014	1,330	123	46	260
Year Over Year Change	647	(17)	(4)	(40)
	95%	(12%)	(8%)	(13%)

ECONOMIC CONTINGENT RESOURCES AND PROSPECTIVE RESOURCES

As at December 31, (billions of barrels, before royalties)	BITUMEN	
	2014	2013
Economic Contingent Resources [1]		
Best Estimate	**9.3**	9.8
Prospective Resources [1] [2]		
Best Estimate	**7.5**	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 no certainty 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 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 and related disclosure is contained in our AIF for the year ended December 31, 2014.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2014	2013	2012
Net Cash From (Used In)			
Operating Activities	**3,526**	3,539	3,420
Investing Activities	**(4,350)**	(1,519)	(3,336)
Net Cash Provided (Used) Before Financing Activities	**(824)**	2,020	84
Financing Activities	**(797)**	(726)	592
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**52**	(2)	(11)
Increase (Decrease) in Cash and Cash Equivalents	**(1,569)**	1,292	665
Cash and Cash Equivalents	**883**	2,452	1,160

OPERATING ACTIVITIES

Cash from operating activities was $13 million lower in 2014 mainly due to lower Cash Flow as discussed in the Financial Results section of this MD&A and the change in non-cash working capital. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $772 million at December 31, 2014 compared with $1,957 million at December 31, 2013. We anticipate that we will continue to meet our payment obligations as they come due.

INVESTING ACTIVITIES

In 2014, cash used in investing activities was $4,350 million, a $2,831 million increase from 2013, primarily due to the prepayment of the US$1.4 billion Partnership Contribution Payable in March 2014 using the funds received from the Partnership Contribution Receivable in December 2013.

FINANCING ACTIVITIES

In 2014, we paid a dividend of $1.0648 per share (2013 – $0.968 per share). Total dividend payments in 2014 were $805 million (2013 – $732 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities increased $71 million primarily due to an increase in dividends paid.

Our long-term debt at December 31, 2014 was $5,458 million (December 31, 2013 – $4,997) 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 $461 million increase in long-term debt is due to foreign exchange.

As at December 31, 2014, we were in compliance with all of the terms of our debt agreements.

AVAILABLE SOURCES OF LIQUIDITY

We expect cash flow from our crude oil, natural gas and refining operations to fund a portion of our cash requirements over the next decade. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us. The following sources of liquidity are available as at December 31, 2014:

($ millions)	AMOUNT	TERM
Cash and Cash Equivalents	883	Not applicable
Committed Credit Facility	3,000	November 2018
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

We have a $3.0 billion committed credit facility. As of December 31, 2014, no amounts were drawn on our committed credit facility.

We have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve undrawn capacity under our committed credit facility for amounts of outstanding commercial paper. As of December 31, 2014, there was no commercial paper outstanding.

U.S. Base Shelf Prospectus

On June 24, 2014, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion, which replaced the U.S. base shelf prospectus dated June 6, 2012, as amended May 9, 2013. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2014, no notes were issued under this U.S. base shelf prospectus.

Canadian Base Shelf Prospectus

On June 25, 2014, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion, which replaced the Canadian base shelf prospectus dated May 24, 2012. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at December 31, 2014, no notes were issued under this Canadian base shelf prospectus.

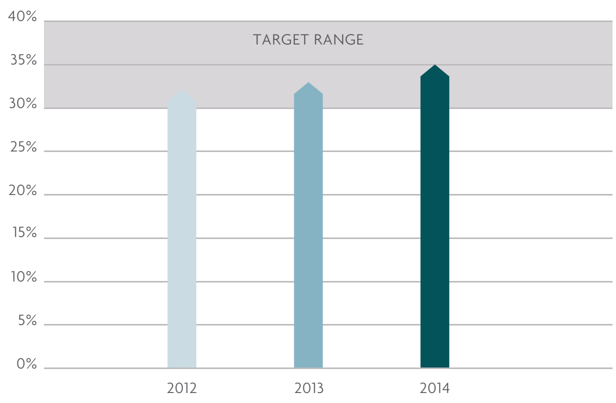
FINANCIAL METRICS

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, 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 12 month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

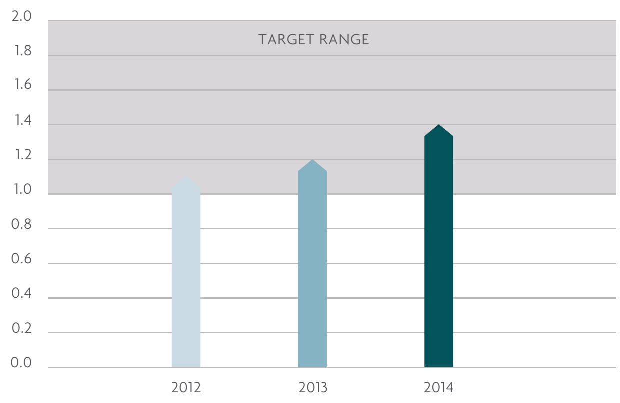
As at December 31,	2014	2013	2012
Debt to Capitalization	35%	33%	32%
Debt to Adjusted EBITDA *(times)*	1.4x	1.2x	1.1x

We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At December 31, 2014, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the middle of our target ranges. The increase in our financial metrics at December 31, 2014 compared to the prior year resulted from higher debt balances as at December 31, 2014, due to changes in foreign exchange consistent with the weakening of the Canadian dollar, and lower Adjusted EBITDA primarily due to a decline in Operating Cash Flow from our Refining and Marketing segment. The weakening of the Canadian dollar has a positive impact on our Operating Cash Flow as the sales prices of our crude oil and refined products are determined by reference to U.S. benchmarks. Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

DEBT TO CAPITALIZATION



DEBT TO ADJUSTED EBITDA



Debt to Capitalization is calculated as follows:

As at December 31,	2014	2013	2012
Debt	5,458	4,997	4,679
Shareholders' Equity	10,186	9,946	9,782
Capitalization	15,644	14,943	14,461
Debt to Capitalization	35%	33%	32%

The following is a reconciliation of Adjusted EBITDA and the calculation of Debt to Adjusted EBITDA:

As at December 31,	2014	2013	2012
Debt	5,458	4,997	4,679
Net Earnings	744	662	995
Add (Deduct):			
Finance Costs	445	529	455
Interest Income	(33)	(96)	(109)
Income Tax Expense	451	432	783
DD&A	1,946	1,833	1,585
Goodwill Impairment	497	–	393
E&E Impairment	86	50	68
Unrealized (Gain) Loss on Risk Management	(596)	415	(57)
Foreign Exchange (Gain) Loss, Net	411	208	(20)
(Gain) Loss on Divestiture of Assets	(156)	1	–
Other (Income) Loss, Net	(4)	2	(5)
Adjusted EBITDA	3,791	4,036	4,088
Debt to Adjusted EBITDA	1.4x	1.2x	1.1x

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

OUTSTANDING SHARE DATA AND STOCK-BASED COMPENSATION PLANS

Cenovus is authorized to issue an unlimited number of common shares and, subject to certain conditions, an unlimited number of first preferred shares and an unlimited number of second preferred shares. At December 31, 2014, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of Cenovus. In addition to its Stock Option Plan, Cenovus has a performance share unit ("PSU") plan and two deferred share unit plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. Refer to Note 27 of the Consolidated Financial Statements for more details.

As at December 31, 2014	UNITS OUTSTANDING *(thousands)*	UNITS EXERCISABLE *(thousands)*
Common Shares	757,103	N/A
Stock Options	44,411	17,301
Other Stock-Based Compensation Plans	8,396	1,297

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

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)	2015	2016	2017	2018	2019	THEREAFTER	TOTAL
Operating							
Pipeline Transportation [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
Other Long-term Commitments	58	24	21	15	13	116	247
Interest on Long-term Debt	293	293	293	293	293	3,720	5,185
Decommissioning Liabilities	38	32	39	65	80	8,079	8,333
Total Operating	1,136	1,115	1,117	1,358	2,136	38,343	45,205
Investing							
Capital Commitments	90	55	11	2	–	46	204
Total Investing	90	55	11	2	–	46	204
Financing							
Long-term Debt (principal only)	–	–	–	–	1,508	4,002	5,510
Total Financing	–	–	–	–	1,508	4,002	5,510
Total Payments [2]	1,226	1,170	1,128	1,360	3,644	42,391	50,919
Fixed Price Product Sales	54	55	3	–	–	–	112

(1) Certain transportation commitments included are subject to regulatory approval.
(2) Contracts on behalf of FCCL Partnership ("FCCL") and WRB Refining LP ("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.

In 2014, commitments for various firm pipeline transportation agreements increased $7 billion due primarily to increased costs and tolls on existing commitments, resulting in total transportation commitments of $28 billion. These agreements, most of which are subject to regulatory approval, are for terms of up to 20 years, subsequent to the date of commencement, and will help align our future transportation requirements with our anticipated production growth. We also entered into rail related commitments that increased our rail takeaway capacity to approximately 30,000 barrels per day at the end of 2014.

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

As at December 31, 2014, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 30 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 23 Bcf of natural gas, at a weighted average price of $4.76 per Mcf.

In the normal course of business, we also lease office space for personnel 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, 2014 or 2013, except for our key management compensation. A summary of key management compensation can be found in the notes to the Consolidated Financial Statements.

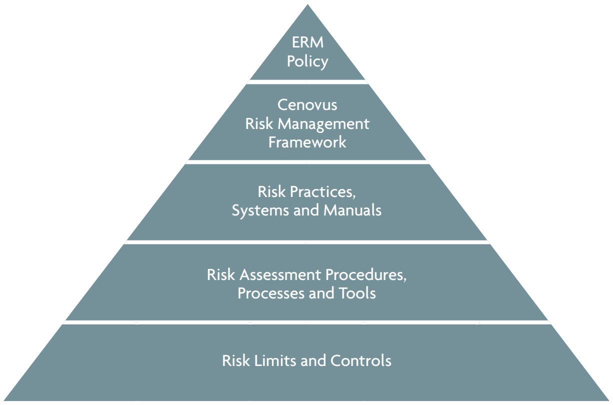
RISK MANAGEMENT

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. Actively managing these risks improves our ability to effectively execute our business strategy. We manage risk to our risk appetite that is determined by Management and confirmed by the Board.

RISK GOVERNANCE

Through our Enterprise Risk Management ("ERM") program, we have established a systematic process for identifying, measuring, prioritizing and managing risk across Cenovus.

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 their *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 the 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 exposures to the right decision makers.

RISK MANAGEMENT ROLES AND RESPONSIBILITIES

The roles and responsibilities of the various participants of our ERM Program are:

The Board:

- Oversees the implementation of the ERM program by Management and provides oversight for risk management activities; and
- The Audit Committee of the Board reviews our Risk Management Framework and related processes on an annual basis to ensure processes remain current and relevant.

Senior Management:

- Confirms our corporate risk appetite with the Board. The executive team is interviewed annually and collaborative workshops are held with Senior Vice-Presidents and Vice-Presidents to support the development of the Annual Risk Report.

The Financial & Enterprise Risk Team reports to the Executive Vice-President & Chief Financial Officer and is responsible for managing our ERM program and the related risk reporting.

PRINCIPAL AND STRATEGIC RISKS

Cenovus's operations, financial condition, and in some cases our reputation, may be impacted by principal and strategic risks. Cenovus defines principal risks as those risks that when measured in terms of likelihood and impact, may adversely affect the achievement of our strategic or major business objectives. Strategic risk is the risk of loss from ineffective business strategies, the absence of integrated business strategies, the inability to implement those strategies, and the inability to adapt the strategies to changes in the external business, political or regulatory environment.

Principal and strategic risks are categorized into:

- Financial risks, which includes commodity price risk and liquidity risk;
- Operational risks such as risks related to health and safety, transportation restrictions, project execution, reserves replacement and the environment; and
- Regulatory risks from the regulatory approval process and changes to or introduction of environmental regulations.

A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2014.

The following explains how material principal and strategic risks impact our business:

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 in commodity prices, interest rates and foreign exchange rates. These contracts may prevent Cenovus from fully realizing the benefit of price or rate increases or decreases above or below those established by these contracts. We have the flexibility to partially mitigate our exposure to interest rate changes by maintaining a mix of fixed and floating rate debt. Credit risk is managed through our credit policy which is approved by the Audit Committee of the Board.

COMMODITY PRICE RISK

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

Changes in commodity prices will affect the revenues generated by the sale of our crude oil and natural gas production from our Oil Sands and Conventional segments and sale of refined products from our refining operations. 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.

A substantial downward shift in the commodity price environment occurred in the fourth quarter of 2014, and since December, crude oil prices have continued to weaken. We are anticipating prices may remain relatively low in 2015. This decline in crude oil prices has resulted 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, the carrying value of our assets may be subject to further impairments, future capital spending could be reduced causing projects to be delayed or cancelled and production could be curtailed, among other impacts. However, lower commodity prices would reduce the cost of natural gas and crude oil feedstock used in our refining operations. As a result of the substantial slowdown across the entire energy sector, we expect to see reductions in demand for labour, service and materials. This should create potential opportunities for us to make improvements in our cost structure.

We manage our commodity price exposure through a combination of activities including business integration, financial hedges and physical contracts. Our business model partially mitigates our exposure to light/heavy differentials and refinery margins through our upstream and downstream integration. In addition, our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our upstream and refining operations. Our capital planning process is flexible, and spending can be reduced in response to declining commodity prices and other economic factors.

We further reduce our exposure to commodity price risk through the use of various financial instruments and select physical contracts. These transactions protect a portion of the budgeted cash flow and ensure funds are available for capital projects. These activities are reviewed and approved by the Market Risk Management Committee which is composed of the President & Chief Executive Officer, Executive Vice-President & Chief Financial Officer and Executive Vice-President, Markets, Products and Transportation. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits.

In 2014, we partially mitigated our exposure to the following:

- Crude oil commodity price risk on our crude oil sales with fixed price commodity swaps and costless collars;
- Natural gas commodity price risk on our natural gas sales with fixed price swaps;
- Location or quality differentials for crude oil with fixed price differential swaps and futures; and
- Electricity consumption costs through a derivative power contract.

For further details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3 and 32 to the Consolidated Financial Statements. The financial impact is summarized below:

Financial Impact of Risk Management Activities

	2014			2013		
($ millions)	REALIZED	UNREALIZED	TOTAL	REALIZED	UNREALIZED	TOTAL
Crude Oil	(37)	(536)	(573)	(71)	343	272
Natural Gas	(7)	(55)	(62)	(63)	69	6
Refining	(26)	(11)	(37)	18	–	18
Power	4	6	10	(6)	3	(3)
(Gain) Loss on Risk Management	(66)	(596)	(662)	(122)	415	293
Income Tax Expense (Recovery)	20	152	172	29	(105)	(76)
(Gain) Loss on Risk Management, After Tax	(46)	(444)	(490)	(93)	310	217

In 2014, management of commodity price risk resulted in realized gains on crude oil and natural gas financial instruments, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized gains on our crude oil and natural gas financial instruments as a result of changes in forward prices for transactions executed during the year, partially offset by the narrowing of forward light/heavy crude oil differentials.

Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the Consolidated Financial Statements.

For our risk management activities, we take an integrated view of our exposure across the upstream and refining businesses. We entered into Brent crude oil and AECO natural gas hedges using fixed-price swap contracts to reduce our commodity price risk on a portion of our expected 2015 production as well as Brent crude oil costless collars to reduce commodity price risk and retain some limited potential upside price exposure. In 2015, we have financially hedged 15 percent of our expected crude oil production on an annualized basis and 34 percent of our expected natural gas production.

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 impacting earnings before income tax on open risk management positions as at December 31, 2014 as follows:

COMMODITY	SENSITIVITY RANGE	INCREASE	DECREASE
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(145)	146
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	5	(5)
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)

LIQUIDITY RISK

Liquidity risk is the risk we will not be able to meet all our financial obligations as they come due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. In declining economic times, such as the low crude oil price environment we are currently operating in, or due to unforeseen events, our liquidity risk could become heightened. If we were unable to meet our financial obligations as they became due this would have a material adverse effect on our financial condition, results of operations, cash flows 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 cash and cash equivalents, cash from operating activities, undrawn credit facilities, commercial paper and availability under our shelf prospectuses. At December 31, 2014, we had cash and cash equivalents of $883 million. No amounts were drawn on our $3.0 billion committed credit facility and no commercial paper was outstanding. 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.

We believe that our current liquidity position is sufficient to protect us in the near-term from liquidity risks related to the effects of lower crude oil prices or from unforeseen economic events that could create further volatility in cash flow.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that could impact the achievement of our objectives.

HEALTH AND SAFETY RISK

Crude oil and natural gas development, production and refining are, by their nature, high risk activities that may cause personal injury or loss of life. The inability to operate safely has the potential to have a material adverse impact on Cenovus's reputation, financial condition, results of operations and cash flow.

We are committed to safety in our operations. We take an active role with our refining partner in ensuring safety is the first priority. Our safety policies and standards comply with government regulations and industry standards. To partially mitigate safety risk, we have a system of standards, practices and procedures called the Cenovus Operations Management System to identify, assess and mitigate safety, operational and environmental risk across our operations. Cenovus endeavours to engage contractors who share the same commitment to safety. We use a third-party online safety prequalification system as well as safety performance data to assist in selecting our contractors. Prevention of occupational diseases and illnesses is also an integral part of our health and safety focus. We take a risk-based approach to systematically identify, evaluate and manage health hazards of all workers at our sites.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies for approval by our Board and oversees compliance with government laws and regulations.

TRANSPORTATION RESTRICTIONS

Our ability to efficiently access end markets may be affected by insufficient transportation capacity for our production. Transportation restrictions can negatively impact financial performance by way of higher transportation costs, wider price differentials, lower sales prices at specific locations or for specific grades and in extreme situations, production curtailment. While this risk may impact our natural gas production, it has the greatest potential to impact our crude oil production, which could negatively affect our financial condition, results of operations and cash flows.

To help mitigate these risks, we employ a diversified sales strategy which includes utilizing multiple transportation options, including pipeline, railcar, marine and cargo. In addition to the firm transportation commitments we have made to date, we continue to evaluate our options. We may further commit to new and expanding transportation infrastructure to access additional markets or invest in technology that improves the efficiency and cost effectiveness of transportation alternatives.

We anticipate transportation constraints will continue in the near term. The Keystone XL project, the Trans Mountain Pipeline Expansion project and the Energy East Pipeline project, if approved, are expected to benefit heavy oil producers by improving access to refineries with capacity to process heavy crude oil as well as creating an option to ship crude oil offshore. The Keystone XL project is expected to connect Alberta's oil sands with refineries in the U.S. Gulf Coast. The Trans Mountain Pipeline Expansion and Northern Gateway Pipeline projects are expected to connect Alberta's oil sands to Canada's West Coast, allowing for transportation to new markets such as Asia. The Energy East Pipeline project is expected to carry crude oil from Alberta and Saskatchewan to refineries and marine terminals in eastern Canada. Other industry options are being developed and we are actively participating in those developments.

CAPITAL PROJECT EXECUTION AND OPERATING RISK

There are risks associated with the execution and operations of our upstream and refining projects. Over the long term, we will be required to concurrently manage multiple projects. Successful project execution will be highly dependent upon the weather, price escalations, availability of skilled labour, key components or other scarce resources and general economic conditions, any of which could have a material adverse effect on Cenovus.

We are also mindful of the need to maintain financial resiliency and control our costs. In January 2015, we revised our 2015 capital budget in response to the current low crude oil price environment. Readers can also review the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at Cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

Our capital programs are scalable in most cases, and if necessary, there are areas where we could defer spending in response to reduced cash flows from operations or liquidity challenges. When making operating and investing decisions, capital allocation is focused on strategic fit, mitigation of risk and optimization of project returns. Our capital approval process requires projects to be presented on a fully risked basis which considers potential construction, commercial, operational and/or regulatory risk exposures. We apply a manufacturing-like approach to our phased oil sands development projects to help manage project quality, scheduling and control costs, including utilizing a templated phase design, in-house project management, construction management and commissioning/start-up teams, and Cenovus's own modular yard for fabrication of pipe rack and equipment modules.

As a result of the substantial slowdown across the entire energy sector, we expect to see reductions in demand for labour, service and materials. This should create potential opportunities for us to drive improvements in our cost structure.

Operational risks 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. Our operational risks include, but are not limited to health and safety considerations, environmental challenges, transportation capacity and interruptions, uncertainty of reserves and resources estimates, reservoir performance and technical challenges, phased execution of oil sands projects and partner risks. In addition to leveraging Cenovus's Operations Management System, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

RESERVES REPLACEMENT RISK

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.

To mitigate the risk associated with replacing reserves we evaluate projects on a fully risked basis, including geological risk and engineering risk, and consider information provided by our stratigraphic well program. In addition, our asset teams undertake a project look-back process, whereby each asset team undertakes a thorough review of its previous capital program to identify key learnings, which often include technical and operational issues that impacted the project's results. Mitigation plans are developed for the issues that had a negative impact on results and are incorporated into the current year's plan.

To date, our ability to find, acquire and develop additional crude oil and natural gas reserves has been in line with our long-range business plan. See the Oil and Gas Reserves and Resources section of this MD&A for further details of our proved and probable reserves and economic bitumen contingent and prospective resources at December 31, 2014.

PERSONNEL

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 personnel or are unsuccessful in attracting and retaining new personnel, 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. Management is investing time and resources in technical and leadership development, defining business processes, standards and metrics, and supporting effective management of change. These are key elements of our Cenovus Operations Management System.

ENVIRONMENTAL RISK

Developing and operating our projects is subject to hazards of recovering, transporting and processing hydrocarbons which can cause damage to the environment. We take our responsibility for the environment very seriously. To manage these risks, we strive to use, recycle and dispose of water safely, manage air emissions, limit our physical footprint and minimize our impact on habitat, including wildlife. Working with our stakeholders, we identify the unique needs of the different areas where we operate. Employees, contractors and third-party service providers have the necessary skills and appropriate training needed to comply with regulations and be responsible environmental stewards. Our environmental impact is measured using the Cenovus Operations Management System to monitor, manage and accurately report our activities.

The Safety, Environment and Responsibility Committee of our Board reviews and recommends policies pertaining to corporate responsibility, including the environment, and oversees compliance with laws and regulations. Monitoring and reporting programs for environmental, health and safety performance in day-to-day operations, as well as inspections and assessments, have been designed to provide assurance that environmental and regulatory standards are met. Contingency plans have been put in place for a timely response to an environmental incident and remediation/reclamation programs are utilized to restore the environment.

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 impose a cost of compliance, adversely impacting our financial condition, results of operations and cash flows.

ENVIRONMENTAL REGULATION RISK

The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations. However, we expect that the cost of meeting new environmental and climate change regulations will not be so high as to cause a material disadvantage to our competitive position. Non-compliance with environmental regulations could also have an adverse impact on Cenovus's reputation.

Further discussion on specific areas that currently have, and are reasonably likely to have, an impact on Cenovus's operations is below.

Species at Risk Act

The federal legislation, *Species at Risk Act*, and provincial counterparts regarding threatened or endangered species may limit the pace and the amount of development in areas identified as critical habitat for species of concern (e.g. woodland caribou). Recent litigation against the federal government in relation to the *Species at Risk Act* has raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. 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 further develop or continue to develop or operate in affected areas.

Water Licenses

To operate our SAGD facilities we rely on water, which is obtained under licenses from Alberta Environment and Sustainable Resource Development. Currently, we are not required to pay for the water we use under these licenses. If a change to the requirements 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. While we currently re-use a percentage of the water which we withdraw under license, there are no guarantees that our operations will continue to efficiently use water.

Greenhouse Gases & Air Pollutants

Various federal, provincial and state governments have announced intentions to regulate greenhouse gas ("GHG") emissions and other air pollutants. A number of legislative and regulatory measures to address GHG emission reductions are in various phases of review, discussion or implementation in Canada and the U.S.

If comprehensive GHG regulation is enacted in any jurisdiction in which we operate, adverse impacts to our business may include, among other things, 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 any 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.

Our approach to emissions management is demonstrated by our industry leadership focusing on energy efficiency, developing oil sands technology to reduce GHG emissions and carbon dioxide sequestration. Cenovus was recognized for leadership in GHG emissions reporting by being included in the 2014 Canada 200 Climate Disclosure Leadership Index. We incorporate the potential costs of carbon, ranging from \$15-\$65 per tonne of CO_2, into future planning which guides the capital allocation process. We intend to continue using scenario planning to anticipate the future impact of regulations, reduce our emissions intensity and improve our energy efficiency.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that may impose costly requirements. In 2007, the Environmental Protection Agency issued the Renewable Fuel Standard program that mandates the total volume of renewable transportation fuel sold or introduced in the U.S. and requires refiners to blend renewable fuels, such as ethanol and advanced biofuels, with their gasoline. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. To the extent refineries do not blend renewable fuels into their petroleum products they must purchase credits, referred to as RINs, in the open market. RINs are a number assigned to each gallon of renewable fuel produced or imported into the U.S., and were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into the motor fuel products we produce and consequently we are obligated to purchase RINs. In the future, the existing regulations could change the volume of renewable fuels required to be blended with refined products. This could create volatility in the price for RINs or an insufficient number of RINs being available to meet the requirements. Our financial condition, results of operations and cash flow could be materially adversely impacted.

Land Use, Habitat and Biodiversity

Alberta's Land-Use Framework has been implemented under the *Alberta Land Stewardship Act* ("ALSA") which sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. In some cases, ALSA amends or extinguishes previously issued consents such as regulatory permits, licenses, approvals and authorizations to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

The Government of Alberta approved the Lower Athabasca Regional Plan ("LARP"), issued under the ALSA. The LARP identifies 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. In 2013, we received financial compensation from the Government of Alberta related to some of our non-core oil sands mineral rights that were cancelled. The cancelled mineral rights had no direct impact on our business plan, our current operations at Foster Creek and Christina Lake or on any of our filed applications. 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.

The Government of Alberta has also approved the South Saskatchewan Regional Plan ("SSRP"), the second regional plan developed under the ALSA. The management framework under the SSRP is similar to the LARP. This plan applies to our conventional operations in southern Alberta. To date, the SSRP is not expected to materially impact our existing conventional operations, but no assurance can be given that future expansion of these operations will not be affected.

The Government of Alberta has also commenced development of its North Saskatchewan Regional Plan ("NSRP"). This plan will apply to Cenovus's operations in central Alberta. The first phase of public consultation for the NSRP is complete. No assurance can be given that the NSRP won't materially impact operations or future operations in this region.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

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 our 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 economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

Identification of CGUs

Our upstream and refining assets are grouped into 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 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 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. Estimates reflect market and regulatory conditions at December 31, 2014, which could differ significantly throughout the year or future period. 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

PP&E, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For our upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as future development and operating expenses. Recoverable amounts for Cenovus's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating expenses, transportation capacity and supply and demand conditions. 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.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

As at December 31, 2014, 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, 2014 by IQREs.

CRUDE OIL AND NATURAL GAS PRICES

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

	2015	2016	2017	2018	2019	AVERAGE ANNUAL % CHANGE TO 2025
WTI *(US$/barrel)*	65.00	75.00	80.00	84.90	89.30	2.5%
WCS *($/barrel)*	57.60	69.90	74.70	79.50	83.70	2.5%
AECO *($/Mcf)*	3.50	4.00	4.25	4.50	4.70	4.1%

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. Changes in economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of our upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, 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 and as a result 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

We adopted the following new amendment:

Offsetting Financial Assets and Financial Liabilities

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

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, 2015 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2014. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

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.

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

Financial Instruments

On July 24, 2014, the IASB issued 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, 2014. 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, 2014.

The effectiveness of our ICFR was audited by PricewaterhouseCoopers LLP, an independent firm of chartered accountants, as stated in their Independent Auditor's Report, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2014. There have been no changes to ICFR during the year ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, our CR approach and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators.

Our CR policy focuses on six commitment areas: (i) Leadership; (ii) Corporate Governance and Business Practices; (iii) People; (iv) Environmental Performance; (v) Stakeholder and Aboriginal Engagement; and (vi) Community Involvement and Investment. We will continue to externally report on our performance in these areas through our annual CR report.

The CR policy emphasizes our commitment to protect the health and safety of all individuals affected by our activities, including our workforce and the communities where we operate. We strive to never compromise the health or safety of any individual in the conduct of our activities. We will strive to provide a safe and healthy work environment and we expect our workers to comply with the health and safety practices established for their protection. Additionally, the CR policy includes reference to emergency response management, investment in efficiency projects, new technologies and research and support of the principles of the Universal Declaration of Human Rights.

We continue to review our CR reporting process, performance indicators and controls to ensure they align with our stakeholder expectations, our operations and our strategy. The CR report is aligned with the Global Reporting Initiative guidelines and the standards set by the Canadian Association of Petroleum Producers in its Responsible Canadian Energy program.

We published our 2013 CR report in July 2014, which highlighted our investments in innovation and research, local and Aboriginal spending in our operating areas, advancements made in minimizing our environmental impacts, long-term agreements signed with Aboriginal communities, and our involvement with and investments in charities and non-profit organizations. Our CR policy and CR report are available on our website at cenovus.com.

In December 2014, we were named to the Canada 200 Climate Disclosure Leadership Index for the fifth consecutive year. This index, published by CDP (formerly known as the Carbon Disclosure Project), recognizes companies for their open and transparent disclosure of greenhouse gas emissions.

In September 2014, our CR practices were recognized internationally with the inclusion of Cenovus in the Dow Jones Sustainability World Index for the third consecutive year. We were also named to the Dow Jones Sustainability North America Index for the fifth consecutive year. The Dow Jones Sustainability Indices track the financial performance of the leading companies worldwide regarding CR performance.

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

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

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

OUTLOOK

We expect 2015 to be a challenging time for our industry. Since December 2014, crude oil prices have continued to weaken and we anticipate prices may remain relatively low throughout 2015. Cenovus remains well positioned. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges in 2015. We continue to pursue our long-term strategy, though at a pace we believe is more in line with the current crude oil pricing environment. We have revised our 2015 budget, reducing our capital spending in order to preserve cash and maintain the strength of our balance sheet. For more information we direct our readers to review our news release dated January 28, 2015, which makes reference to our revised 2015 budget and our news release dated December 11, 2014, which includes our previously disclosed net asset value target. The news releases are available on our website at cenovus.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Our crude oil pricing outlook is influenced by the following:

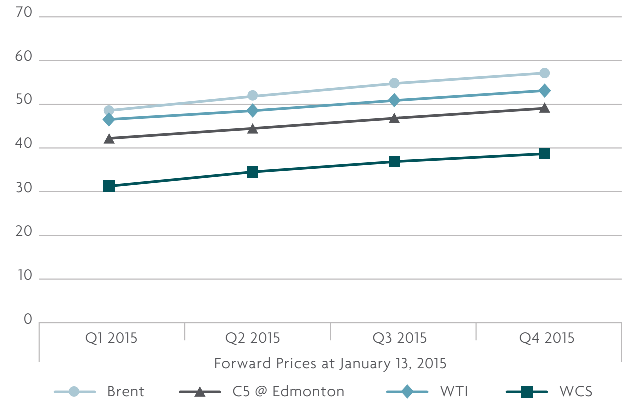
- We expect the general outlook for crude oil prices will be tied primarily to the non-OPEC supply response to the current price environment and the pace of growth of the global economy. Overall, we expect Brent crude oil prices to decline as we enter the seasonally weak demand period in the spring which could result in shut-in of the least economic production as measured by variable costs. A reduction in global supply growth, combined with annual increases in demand growth and seasonal impacts in the last half of the year will help slightly improve prices for the remainder of the year as reflected in the forward curve. Most North American producers have announced significant reductions in capital spending which should slow supply growth in the coming quarters. However, we anticipate that potential supply reductions from global non-tight oil producers will not be as significant due to more stable production profiles and historically longer lead-times to bring on projects. The current low crude oil price environment also serves to help boost global economic momentum which, with the exception of the U.S., has been faced with mounting deflationary concerns and transitioning emerging markets. By mid-year, OPEC may reduce production and provide some support to prices if they see that action has been taken by the market which will enable OPEC to sustain market share. Longer term, low crude oil prices should push producers to reduce costs and improve efficiencies thereby resulting in sustained lower crude oil prices as compared to recent years. However, if OPEC continues to abandon its historic swing supplier role, price volatility will be significantly greater than historic norms;
- Overall, we expect the Brent-WTI differential to remain consistent with levels experienced at the end of 2014. A decline in crude oil supply growth, as discussed above, would decrease the impact that North American crude oil congestion could have on the differential; and
- The WTI-WCS differential will continue to be set by the marginal transportation cost to the U.S. Gulf Coast. With increased rail infrastructure planned over the coming year, along with incremental pipeline capacity, we expect higher levels of spare takeaway capacity from Alberta. Despite some volatility in the differential due to uncertainty around the timing of new infrastructure, we expect a narrower differential as compared to levels experienced at the end of 2014.

We expect average market crack spreads to remain relatively steady compared to the end of 2014 until an increase in seasonal demand in the U.S. results in an improvement in refined product prices.

Natural gas prices are expected to decline throughout 2015 as compared to prices at the end of 2014. The inventory of drilled but uncompleted wells should keep supply growth strong even with a decline in industry activity.

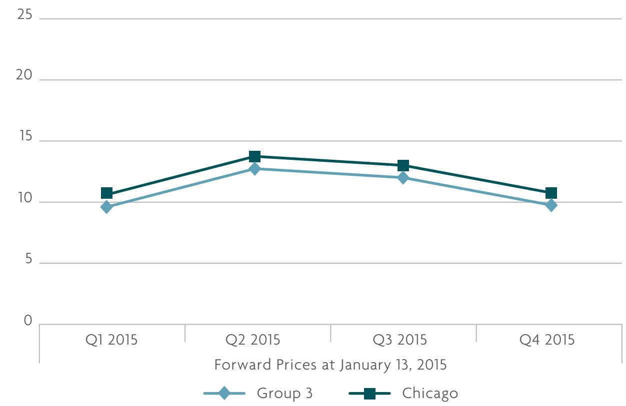
CRUDE OIL BENCHMARKS

(average US$/bbl)



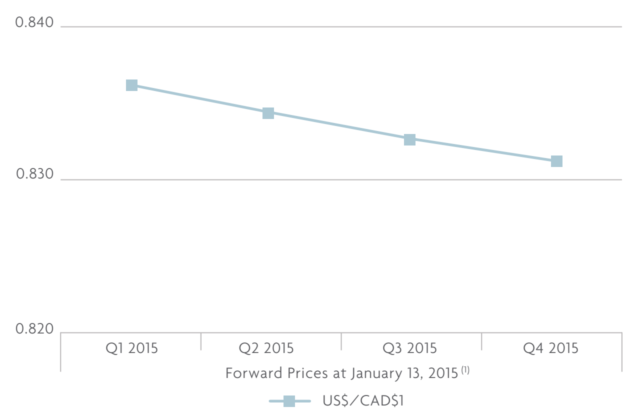
REFINING 3-2-1 CRACK SPREAD BENCHMARKS

(average US$/bbl)



FOREIGN EXCHANGE RATES

(average US$/C$1)

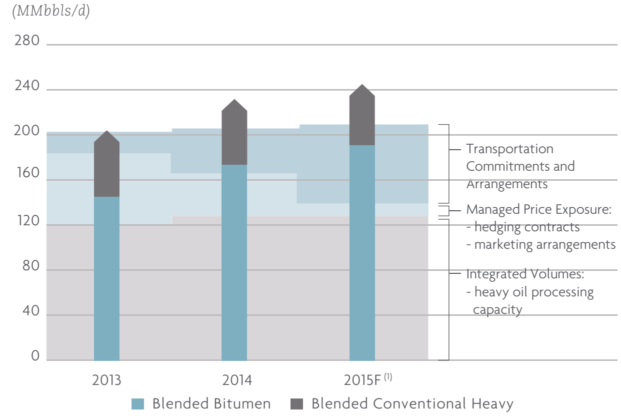


(1) Refer to the foreign exchange rate sensitivities found within our current guidance available at cenovus.com.

The average foreign exchange forward price over the next four quarters is US$0.834/C$1. The recent Bank of Canada rate cut has acted to further depress the Canadian dollar against its U.S. counterpart. U.S. economic momentum and timing of key interest rate decisions, both in Canada and the U.S., will largely dictate future foreign exchange fluctuations. Overall, we expect the Canadian dollar to remain relatively weak over the next twelve months as compared to prices at the end of 2014, which would 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 prices, we mitigate our exposure to light/heavy price differentials through the following:

PROTECTION AGAINST CANADIAN CONGESTION



(1) Expected gross production capacity.

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

KEY PRIORITIES FOR 2015

Maintain Financial Resilience

We have strong producing assets, an integrated portfolio and a solid balance sheet which have positioned us well to face the challenges in 2015. Our capital planning process is flexible and spending can be reduced in response to commodity prices and other economic factors, so we can maintain our financial strength and resiliency, advance our strategy and not compromise our future plans. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in 2015.

Attack Cost Structures

We continue to challenge cost structures across the organization to maintain our track record of cost efficiency. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure and maximize the strengths of our business model. We have identified opportunities to achieve between $400 million and $500 million in anticipated annual operating and capital cost reductions in the years ahead.

As a result of the slowdown across the energy sector, we expect to see reductions in demand for labour, service and materials. This should create opportunities for us to make improvements in our cost structure.

Enable Market Access

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

During 2014, we entered into approximately $7 billion of new pipeline commitments (most of which include amounts for projects awaiting regulatory approval) to align our future transportation requirements with our anticipated growth. In addition, we increased our rail takeaway capacity for crude oil to approximately 30,000 barrels per day.

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A.

CONSOLIDATED FINANCIAL STATEMENTS

For the Year Ended December 31, 2014
(Canadian Dollars)

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 three 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, 2014. 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, 2014.

PricewaterhouseCoopers LLP, an independent firm of Chartered 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, 2014, as stated in their Auditor's Report dated February 11, 2015. PricewaterhouseCoopers LLP has provided such opinions.

BRIAN C. FERGUSON
President & Chief Executive Officer
Cenovus Energy Inc.

IVOR M. RUSTE
Executive Vice-President & Chief Financial Officer
Cenovus Energy Inc.

February 11, 2015

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF CENOVUS ENERGY INC.

We have completed an integrated audit of Cenovus Energy Inc.'s 2014, 2013 and 2012 Consolidated Financial Statements and its internal control over financial reporting as at December 31, 2014. Our opinions, based on our audits, are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying Consolidated Financial Statements of Cenovus Energy Inc., which comprise the Consolidated Balance Sheets as at December 31, 2014 and December 31, 2013 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years ended December 31, 2014, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these Consolidated Financial Statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these Consolidated Financial Statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards require that we comply with ethical requirements.

An audit involves performing procedures to obtain audit evidence, on a test basis, about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting principles and policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion on the Consolidated Financial Statements.

OPINION

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the financial position of Cenovus Energy Inc. as at December 31, 2014 and December 31, 2013 and its financial performance and cash flows for each of the three years ended December 31, 2014 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013), issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

MANAGEMENT'S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible 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.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on Cenovus Energy Inc.'s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects.

An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control, based on the assessed risk, and performing such other procedures as we consider necessary in the circumstances.

We believe that our audit provides a reasonable basis for our audit opinion on Cenovus Energy Inc.'s internal control over financial reporting.

DEFINITION OF INTERNAL CONTROL OVER FINANCIAL REPORTING

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.

INHERENT LIMITATIONS

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.

OPINION

In our opinion, Cenovus Energy Inc. maintained, in all material respects, effective internal control over financial reporting as at December 31, 2014 based on criteria established in Internal Control – Integrated Framework (2013), issued by COSO.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP
Chartered Accountants
Calgary, Alberta, Canada

February 11, 2015

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31, ($ millions, except per share amounts)	NOTES	2014	2013	2012
Revenues	1			
Gross Sales		20,107	18,993	17,229
Less: Royalties		465	336	387
		19,642	18,657	16,842
Expenses	1			
Purchased Product		10,955	10,399	9,223
Transportation and Blending		2,477	2,074	1,798
Operating		2,066	1,798	1,667
Production and Mineral Taxes		46	35	37
(Gain) Loss on Risk Management	31	(662)	293	(393)
Depreciation, Depletion and Amortization	15,16	1,946	1,833	1,585
Goodwill Impairment	18	497	–	393
Exploration Expense	14	86	114	68
General and Administrative		358	349	350
Finance Costs	6	445	529	455
Interest Income	7	(33)	(96)	(109)
Foreign Exchange (Gain) Loss, Net	8	411	208	(20)
Research Costs		15	24	15
(Gain) Loss on Divestiture of Assets	16	(156)	1	–
Other (Income) Loss, Net		(4)	2	(5)
Earnings Before Income Tax		1,195	1,094	1,778
Income Tax Expense	9	451	432	783
Net Earnings		744	662	995
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		(18)	14	(4)
Items That May be Reclassified to Profit or Loss:				
Change in Value of Available for Sale Financial Assets		–	10	–
Foreign Currency Translation Adjustment		215	117	(24)
Total Other Comprehensive Income (Loss), Net of Tax		197	141	(28)
Comprehensive Income		941	803	967
Net Earnings Per Common Share	10			
Basic		$0.98	$0.88	$1.32
Diluted		$0.98	$0.87	$1.31

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31, *($ millions)*	NOTES	2014	2013
Assets			
Current Assets			
Cash and Cash Equivalents	11	883	2,452
Accounts Receivable and Accrued Revenues	12	1,582	1,874
Income Tax Receivable		28	15
Inventories	13	1,224	1,259
Risk Management	31	478	10
Current Assets		4,195	5,610
Exploration and Evaluation Assets	1,14	1,625	1,473
Property, Plant and Equipment, Net	1,15	18,563	17,334
Other Assets	17	70	68
Goodwill	1,18	242	739
Total Assets		24,695	25,224
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	19	2,588	2,937
Income Tax Payable		357	268
Current Portion of Partnership Contribution Payable	20	–	438
Risk Management	31	12	136
Current Liabilities		2,957	3,779
Long-Term Debt	21	5,458	4,997
Partnership Contribution Payable	20	–	1,087
Risk Management	31	4	3
Decommissioning Liabilities	22	2,616	2,370
Other Liabilities	23	172	180
Deferred Income Taxes	9	3,302	2,862
Total Liabilities		14,509	15,278
Shareholders' Equity		10,186	9,946
Total Liabilities and Shareholders' Equity		24,695	25,224
Commitments and Contingencies	34		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

MICHAEL A. GRANDIN
Director
Cenovus Energy Inc.

COLIN TAYLOR
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)	SHARE CAPITAL	PAID IN SURPLUS	RETAINED EARNINGS	AOCI [(1)]	TOTAL
	(Note 25)	*(Note 25)*		*(Note 26)*	
Balance as at December 31, 2011	3,780	4,107	1,400	97	9,384
Net Earnings	–	–	995	–	995
Other Comprehensive Income (Loss)	–	–	–	(28)	(28)
Total Comprehensive Income (Loss)	–	–	995	(28)	967
Common Shares Issued Under Stock Option Plans	49	–	–	–	49
Stock-Based Compensation Expense	–	47	–	–	47
Dividends on Common Shares	–	–	(665)	–	(665)
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**

(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	2014	2013	2012
Operating Activities				
Net Earnings		744	662	995
Depreciation, Depletion and Amortization	15	1,946	1,833	1,585
Goodwill Impairment	18	497	–	393
Exploration Expense	14	86	50	68
Deferred Income Taxes	9	359	244	474
Unrealized (Gain) Loss on Risk Management	31	(596)	415	(57)
Unrealized Foreign Exchange (Gain) Loss	8	411	40	(70)
(Gain) Loss on Divestiture of Assets	16	(156)	1	–
Unwinding of Discount on Decommissioning Liabilities	6,22	120	97	86
Other		68	267	169
		3,479	3,609	3,643
Net Change in Other Assets and Liabilities		(135)	(120)	(113)
Net Change in Non-Cash Working Capital		182	50	(110)
Cash From Operating Activities		3,526	3,539	3,420
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	14	(279)	(331)	(654)
Capital Expenditures – Property, Plant and Equipment	15	(2,779)	(2,938)	(2,795)
Proceeds From Divestiture of Assets	16	276	258	76
Net Change in Investments and Other	20	(1,583)	1,486	(13)
Net Change in Non-Cash Working Capital		15	6	50
Cash (Used in) Investing Activities		(4,350)	(1,519)	(3,336)
Net Cash Provided (Used) Before Financing Activities		(824)	2,020	84
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		(18)	(8)	3
Issuance of U.S. Unsecured Notes	21	–	814	1,219
Repayment of U.S. Unsecured Notes	21	–	(825)	–
Proceeds on Issuance of Common Shares		28	28	37
Dividends Paid on Common Shares	10	(805)	(732)	(665)
Other		(2)	(3)	(2)
Cash From (Used in) Financing Activities		(797)	(726)	592
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		52	(2)	(11)
Increase (Decrease) in Cash and Cash Equivalents		(1,569)	1,292	665
Cash and Cash Equivalents, Beginning of Year		2,452	1,160	495
Cash and Cash Equivalents, End of Year		883	2,452	1,160
Supplementary Cash Flow Information	33			

See accompanying Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

All amounts in $ millions, unless otherwise indicated
For the year ended December 31, 2014

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

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

Cenovus is incorporated under the *Canada Business Corporations Act* and its shares are publicly traded 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 Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake. This segment also includes the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **Refining and Marketing,** which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Corporate and Eliminations,** which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

The following tabular financial information presents the segmented information first by segment, then by product and geographic location.

A) RESULTS OF OPERATIONS – SEGMENT AND OPERATIONAL INFORMATION

	OIL SANDS			CONVENTIONAL			REFINING AND MARKETING		
For the years ended December 31,	2014	2013	2012	2014	2013	2012	2014	2013	2012
Revenues									
Gross Sales	5,036	3,912	3,356	3,225	2,980	2,800	12,658	12,706	11,356
Less: Royalties	236	132	186	229	204	201	–	–	–
	4,800	3,780	3,170	2,996	2,776	2,599	12,658	12,706	11,356
Expenses									
Purchased Product	–	–	–	–	–	–	11,767	11,004	9,506
Transportation and Blending	2,131	1,749	1,501	346	325	297	–	–	–
Operating	647	555	426	718	708	662	707	540	581
Production and Mineral Taxes	–	–	–	46	35	37	–	–	–
(Gain) Loss on Risk Management	(38)	(37)	(64)	(1)	(104)	(268)	(27)	19	(4)
Operating Cash Flow	2,060	1,513	1,307	1,887	1,812	1,871	211	1,143	1,273
Depreciation, Depletion and Amortization	625	446	339	1,082	1,170	1,048	156	138	146
Goodwill Impairment	–	–	–	497	–	393	–	–	–
Exploration Expense	4	–	–	82	114	68	–	–	–
Segment Income	1,431	1,067	968	226	528	362	55	1,005	1,127

	CORPORATE AND ELIMINATIONS			CONSOLIDATED		
For the years ended December 31,	2014	2013	2012	2014	2013	2012
Revenues						
Gross Sales	(812)	(605)	(283)	20,107	18,993	17,229
Less: Royalties	–	–	–	465	336	387
	(812)	(605)	(283)	19,642	18,657	16,842
Expenses						
Purchased Product	(812)	(605)	(283)	10,955	10,399	9,223
Transportation and Blending	–	–	–	2,477	2,074	1,798
Operating	(6)	(5)	(2)	2,066	1,798	1,667
Production and Mineral Taxes	–	–	–	46	35	37
(Gain) Loss on Risk Management	(596)	415	(57)	(662)	293	(393)
	602	(410)	59	4,760	4,058	4,510
Depreciation, Depletion and Amortization	83	79	52	1,946	1,833	1,585
Goodwill Impairment	–	–	–	497	–	393
Exploration Expense	–	–	–	86	114	68
Segment Income (Loss)	519	(489)	7	2,231	2,111	2,464
General and Administrative	358	349	350	358	349	350
Finance Costs	445	529	455	445	529	455
Interest Income	(33)	(96)	(109)	(33)	(96)	(109)
Foreign Exchange (Gain) Loss, Net	411	208	(20)	411	208	(20)
Research Costs	15	24	15	15	24	15
(Gain) Loss on Divestiture of Assets	(156)	1	–	(156)	1	–
Other (Income) Loss, Net	(4)	2	(5)	(4)	2	(5)
	1,036	1,017	686	1,036	1,017	686
Earnings Before Income Tax				1,195	1,094	1,778
Income Tax Expense				451	432	783
Net Earnings				744	662	995

B) FINANCIAL RESULTS BY UPSTREAM PRODUCT

	CRUDE OIL [1]								
	OIL SANDS			CONVENTIONAL			TOTAL		
For the years ended December 31,	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues									
Gross Sales	**4,963**	3,850	3,307	**2,456**	2,373	2,289	**7,419**	6,223	5,596
Less: Royalties	**233**	131	186	**217**	196	195	**450**	327	381
	4,730	3,719	3,121	**2,239**	2,177	2,094	**6,969**	5,896	5,215
Expenses									
Transportation and Blending	**2,130**	1,748	1,499	**326**	305	278	**2,456**	2,053	1,777
Operating	**622**	531	401	**512**	495	441	**1,134**	1,026	842
Production and Mineral Taxes	**–**	–	–	**37**	32	34	**37**	32	34
(Gain) Loss on Risk Management	**(38)**	(33)	(46)	**4**	(43)	(39)	**(34)**	(76)	(85)
Operating Cash Flow	**2,016**	1,473	1,267	**1,360**	1,388	1,380	**3,376**	2,861	2,647

(1) Includes NGLs.

	NATURAL GAS								
	OIL SANDS			CONVENTIONAL			TOTAL		
For the years ended December 31,	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues									
Gross Sales	**67**	38	38	**744**	594	498	**811**	632	536
Less: Royalties	**3**	1	–	**12**	8	6	**15**	9	6
	64	37	38	**732**	586	492	**796**	623	530
Expenses									
Transportation and Blending	**1**	1	2	**20**	20	19	**21**	21	21
Operating	**18**	18	23	**200**	209	217	**218**	227	240
Production and Mineral Taxes	**–**	–	–	**9**	3	3	**9**	3	3
(Gain) Loss on Risk Management	**–**	(4)	(18)	**(5)**	(61)	(229)	**(5)**	(65)	(247)
Operating Cash Flow	**45**	22	31	**508**	415	482	**553**	437	513

	OTHER								
	OIL SANDS			CONVENTIONAL			TOTAL		
For the years ended December 31,	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues									
Gross Sales	**6**	24	11	**25**	13	13	**31**	37	24
Less: Royalties	**–**	–	–	**–**	–	–	**–**	–	–
	6	24	11	**25**	13	13	**31**	37	24
Expenses									
Transportation and Blending	**–**	–	–	**–**	–	–	**–**	–	–
Operating	**7**	6	2	**6**	4	4	**13**	10	6
Production and Mineral Taxes	**–**	–	–	**–**	–	–	**–**	–	–
(Gain) Loss on Risk Management	**–**	–	–	**–**	–	–	**–**	–	–
Operating Cash Flow	**(1)**	18	9	**19**	9	9	**18**	27	18

	TOTAL UPSTREAM								
	OIL SANDS			CONVENTIONAL			TOTAL		
For the years ended December 31,	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues									
Gross Sales	**5,036**	3,912	3,356	**3,225**	2,980	2,800	**8,261**	6,892	6,156
Less: Royalties	**236**	132	186	**229**	204	201	**465**	336	387
	4,800	3,780	3,170	**2,996**	2,776	2,599	**7,796**	6,556	5,769
Expenses									
Transportation and Blending	**2,131**	1,749	1,501	**346**	325	297	**2,477**	2,074	1,798
Operating	**647**	555	426	**718**	708	662	**1,365**	1,263	1,088
Production and Mineral Taxes	**–**	–	–	**46**	35	37	**46**	35	37
(Gain) Loss on Risk Management	**(38)**	(37)	(64)	**(1)**	(104)	(268)	**(39)**	(141)	(332)
Operating Cash Flow	**2,060**	1,513	1,307	**1,887**	1,812	1,871	**3,947**	3,325	3,178

C) GEOGRAPHIC INFORMATION

	CANADA			UNITED STATES			CONSOLIDATED		
For the years ended December 31,	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Revenues									
Gross Sales	**10,604**	8,943	8,069	**9,503**	10,050	9,160	**20,107**	18,993	17,229
Less: Royalties	**465**	336	387	**–**	–	–	**465**	336	387
	10,139	8,607	7,682	**9,503**	10,050	9,160	**19,642**	18,657	16,842
Expenses									
Purchased Product	**2,310**	2,022	1,884	**8,645**	8,377	7,339	**10,955**	10,399	9,223
Transportation and Blending	**2,477**	2,074	1,798	**–**	–	–	**2,477**	2,074	1,798
Operating	**1,387**	1,276	1,108	**679**	522	559	**2,066**	1,798	1,667
Production and Mineral Taxes	**46**	35	37	**–**	–	–	**46**	35	37
(Gain) Loss on Risk Management	**(625)**	275	(385)	**(37)**	18	(8)	**(662)**	293	(393)
	4,544	2,925	3,240	**216**	1,133	1,270	**4,760**	4,058	4,510
Depreciation, Depletion and Amortization	**1,790**	1,695	1,439	**156**	138	146	**1,946**	1,833	1,585
Goodwill Impairment	**497**	–	393	**–**	–	–	**497**	–	393
Exploration Expense	**86**	114	68	**–**	–	–	**86**	114	68
Segment Income	**2,171**	1,116	1,340	**60**	995	1,124	**2,231**	2,111	2,464

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

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 $821 million (2013 – $926 million; 2012 – $671 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, 2014, Cenovus had three customers (2013 – three; 2012 – 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 $7,210 million, $2,668 million and $2,316 million, respectively (2013 – $7,032 million, $2,711 million and $1,799 million; 2012 – $3,928 million, $3,300 million and $2,839 million).

D) JOINT OPERATIONS

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

FCCL, which is involved in the development and production of crude oil in Canada, is jointly controlled with ConocoPhillips and operated by Cenovus. WRB has two refineries in the U.S. and focuses on the refining of crude oil into petroleum and chemical products. WRB is jointly controlled with and operated by Phillips 66. Cenovus's share of operating cash flow from FCCL and WRB for the year ended December 31, 2014 was $1,933 million and $214 million, respectively (2013 – $1,383 million and $1,144 million; 2012 – $1,188 million and $1,274 million).

E) EXPLORATION AND EVALUATION ASSETS, PROPERTY, PLANT AND EQUIPMENT, GOODWILL AND TOTAL ASSETS

BY SEGMENT

	E&E [1]		PP&E [2]	
As at December 31,	2014	2013	2014	2013
Oil Sands	1,540	1,328	8,606	7,401
Conventional	85	145	6,038	6,291
Refining and Marketing	–	–	3,568	3,269
Corporate and Eliminations	–	–	351	373
Consolidated	1,625	1,473	18,563	17,334

	GOODWILL		TOTAL ASSETS	
As at December 31,	2014	2013	2014	2013
Oil Sands	242	242	11,024	9,564
Conventional	–	497	6,211	7,220
Refining and Marketing	–	–	5,520	5,491
Corporate and Eliminations	–	–	1,940	2,949
Consolidated	242	739	24,695	25,224

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

BY GEOGRAPHIC REGION

	E&E		PP&E	
As at December 31,	2014	2013	2014	2013
Canada	1,625	1,473	14,999	14,066
United States	–	–	3,564	3,268
Consolidated	1,625	1,473	18,563	17,334

	GOODWILL		TOTAL ASSETS	
As at December 31,	2014	2013	2014	2013
Canada	242	739	20,231	20,548
United States	–	–	4,464	4,676
Consolidated	242	739	24,695	25,224

F) CAPITAL EXPENDITURES [1]

For the years ended December 31,	2014	2013	2012
Capital			
Oil Sands	1,986	1,885	1,697
Conventional	840	1,189	1,362
Refining and Marketing	163	107	118
Corporate	62	81	191
	3,051	3,262	3,368
Acquisition Capital			
Oil Sands [2]	15	27	69
Conventional	3	5	45
	3,069	3,294	3,482

(1) Includes expenditures on PP&E and E&E.
(2) The 2014 acquisition capital includes the assumption of a decommissioning liability of $10 million (2013 – $nil; 2012 – $33 million).

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 11, 2015.

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. The Company recognizes its share of assets, liabilities, revenues and expenses of a joint operation. Joint ventures arise when the Company has rights to the net assets of the arrangement. Joint ventures are accounted for under the equity method.

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 at the average rate 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 and Comprehensive Income.

C) REVENUE AND INTEREST INCOME RECOGNITION

SALES OF PRODUCT

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.

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.

INTEREST INCOME

Interest income is recognized as the interest accrues using the effective interest method.

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) PRODUCTION AND MINERAL TAXES

Costs paid to non-mineral interest owners based on production of crude oil, natural gas and NGLs are recognized when the product is sold.

F) 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.

G) 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 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.
- 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 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.

H) INCOME TAXES

Income taxes comprise current and deferred taxes. Current and deferred 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.

I) NET EARNINGS PER SHARE AMOUNTS

Basic net earnings per common 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.

J) 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.

K) 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.

L) ASSETS (DISPOSAL GROUPS) HELD FOR SALE

Non-current assets or disposal groups are classified as held for sale when their carrying amount will be principally recovered through a sales transaction rather than through continued use and a sales transaction is highly probable. Assets held for sale are recorded at the lower of carrying value and fair value less costs of disposal.

M) 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 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.

Once technical feasibility and commercial viability have been established for a field/project/area, the carrying value of the E&E assets associated with that field/project/area is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources. If a field/project/area is determined not to be technically feasible and commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense in the period in which the determination occurs.

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

N) PROPERTY, PLANT AND EQUIPMENT

DEVELOPMENT AND PRODUCTION ASSETS

Development and production assets are stated at cost less accumulated depreciation, depletion and amortization ("DD&A"), and net impairment losses. 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 commercial 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 forecast 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.

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 development and production assets are recognized in net earnings.

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 refining assets are stated at cost less accumulated depreciation and net impairment losses.

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. Maintenance and repairs are expensed as incurred.

Capitalized costs are not subject to depreciation until the asset is available for use, after which they 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 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 25 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. Assets under construction are not subject to depreciation until they are available for use. 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.

O) IMPAIRMENT

NON-FINANCIAL ASSETS

PP&E and E&E assets are assessed for impairment at least annually or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. The recoverable amount is determined as the greater of an asset's or cash-generating unit's ("CGU") 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 based on the discounted after-tax cash flows of reserves and resources using forecast prices and costs, consistent with Cenovus's independent qualified reserves evaluators, and an evaluation of comparable asset transactions.

The impairment test is performed at the CGU for development and production assets and other upstream assets. E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Corporate assets are allocated to the CGUs to which they contribute to the future cash flows. For refining assets, the impairment test is performed at each refinery independently.

Impairment losses on PP&E are recognized in the Consolidated Statements of Earnings and Comprehensive Income as additional DD&A and are separately disclosed. An impairment of E&E assets is recognized as exploration expense in the Consolidated Statements of Earnings and Comprehensive Income.

Goodwill is assessed for impairment at least annually. To assess impairment, the recoverable amount of the CGU to which the goodwill relates is compared to the carrying amount. 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.

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.

P) BORROWING COSTS

Borrowing costs are expensed as incurred unless there is a qualifying asset. Borrowing costs directly associated with the acquisition, construction or production of a qualifying asset are capitalized when a substantial period of time is required to make the asset ready for its intended use. Capitalization of borrowing costs ceases when the asset is in the location and condition necessary for its intended use.

Q) 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.

R) 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.

S) 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 and Comprehensive Income.

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 and refining facilities. 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. Increases in the decommissioning liabilities resulting from the passage of time are recognized as a finance cost in the Consolidated Statements of Earnings and Comprehensive Income.

Actual expenditures incurred are charged against the accumulated liability.

T) 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.

U) STOCK-BASED COMPENSATION

Cenovus has a number of cash and 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") and deferred share units ("DSUs").

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 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 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 AND DEFERRED SHARE UNITS

PSUs 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 compensation costs over the vesting period. Fluctuations in the fair values are recognized as compensation costs in the period they occur.

V) FINANCIAL INSTRUMENTS

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 and Comprehensive Income.

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.

The Company's consolidated financial assets include cash and cash equivalents, accounts receivable and accrued revenues, risk management assets and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, the Partnership Contribution Payable, derivative financial instruments, short-term borrowings and long-term debt.

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.

HELD TO MATURITY INVESTMENTS

"Held-to-maturity investments" are measured at amortized cost using the effective interest method of amortization.

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.

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, the Partnership Contribution Payable, 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.

W) RECLASSIFICATION

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2014.

X) RECENT ACCOUNTING PRONOUNCEMENTS

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, 2015 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2014. The standards applicable to the Company are as follows and will be adopted on their respective effective dates:

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

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. 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. CHANGE IN ACCOUNTING POLICIES

NEW AND AMENDED ACCOUNTING STANDARDS ADOPTED

The Company adopted the following new amendment:

Offsetting Financial Assets and Financial Liabilities

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

5. 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, 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 economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible and commercially viable or Management decides not to continue the exploration and evaluation activity, the unrecoverable costs are charged to exploration expense.

IDENTIFICATION OF CGUs

The Company's upstream and refining assets are grouped into 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 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 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

PP&E, E&E assets and goodwill are assessed for impairment at least annually and when circumstances suggest that the carrying amount may exceed the recoverable amount. Assets are tested for impairment at the CGU level. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available. For the Company's upstream assets, these estimates include future commodity prices, expected production volumes, quantity of reserves and discount rates, as well as future development and operating expenses. Recoverable amounts for the Company's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating expenses, transportation capacity, and supply and demand conditions. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

For impairment testing purposes, goodwill has been allocated to each of the CGUs to which it relates.

As at December 31, 2014, 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, 2014 by independent qualified reserves evaluators.

Crude Oil and Natural Gas Prices

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

	2015	2016	2017	2018	2019	AVERAGE ANNUAL % CHANGE TO 2025
WTI *(US$/barrel)* (1)	65.00	75.00	80.00	84.90	89.30	2.5%
WCS *($/barrel)* (2)	57.60	69.90	74.70	79.50	83.70	2.5%
AECO *($/Mcf)* (3)	3.50	4.00	4.25	4.50	4.70	4.1%

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Assumes gas heating value of 1 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. Changes in economic conditions could significantly change the estimated recoverable amount.

DECOMMISSIONING COSTS

Provisions are recorded for the future decommissioning and restoration of the Company's upstream crude oil and natural gas assets and refining assets at the end of their economic lives. Assumptions have been made to estimate the future liability based on past experience and current economic factors which Management believes are reasonable. However, 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.

6. FINANCE COSTS

For the years ended December 31,	2014	2013	2012
Interest Expense – Short-Term Borrowings and Long-Term Debt	285	271	230
Premium on Redemption of Long-Term Debt	–	33	–
Interest Expense – Partnership Contribution Payable *(Note 20)*	22	98	118
Unwinding of Discount on Decommissioning Liabilities *(Note 22)*	120	97	86
Other	18	30	21
	445	529	455

7. INTEREST INCOME

For the years ended December 31,	2014	2013	2012
Interest Income – Partnership Contribution Receivable	–	(82)	(102)
Other	(33)	(14)	(7)
	(33)	(96)	(109)

In 2013, Cenovus, through its interest in FCCL, received the remaining principal and interest due under the Partnership Contribution Receivable.

8. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	2014	2013	2012
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued from Canada	458	357	(69)
U.S. Dollar Partnership Contribution Receivable Issued from Canada	–	(305)	(15)
Other	(47)	(12)	14
Unrealized Foreign Exchange (Gain) Loss	411	40	(70)
Realized Foreign Exchange (Gain) Loss	–	168	50
	411	208	(20)

9. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	2014	2013	2012
Current Tax			
Canada	94	143	188
United States [1]	(2)	45	121
Total Current Tax	92	188	309
Deferred Tax	359	244	474
	451	432	783

(1) 2012 includes $68 million of withholding tax on a U.S. dividend.

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

For the years ended December 31,	2014	2013	2012
Earnings Before Income Tax	1,195	1,094	1,778
Canadian Statutory Rate	25.2%	25.2%	25.2%
Expected Income Tax	301	276	448
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	(43)	87	119
Non-deductible Stock-Based Compensation	13	10	10
Foreign Exchange Gains (Losses) not Included in Net Earnings	(13)	19	14
Non-taxable Capital (Gains) Losses	124	31	(7)
Derecognition (Recognition) of Capital Losses	(9)	15	(22)
Adjustments Arising From Prior Year Tax Filings	(16)	(13)	33
Withholding Tax on Foreign Dividend	–	–	68
Goodwill Impairment	125	–	99
Other	(31)	7	21
Total Tax	451	432	783
Effective Tax Rate	37.7%	39.5%	44.0%

The Canadian statutory tax rate remained unchanged at 25.2 percent for the years presented. The U.S. statutory tax rate has decreased to 38.1 percent in 2014 from 38.5 percent in 2013 and 2012 as a result of the allocation of taxable income to U.S. states the Company operates in.

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

As at December 31,	2014	2013
Net Deferred Income Tax Liabilities		
Deferred Tax Liabilities to be Settled Within 12 Months	296	75
Deferred Tax Liabilities to be Settled After More Than 12 Months	3,006	2,787
	3,302	2,862

For the purposes of the preceding table, deferred income tax liabilities are shown net of offsetting deferred income tax assets where these 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 does 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	NET FOREIGN EXCHANGE GAINS	RISK MANAGEMENT	OTHER	TOTAL
As at December 31, 2012	2,795	59	27	73	99	3,053
Charged/(Credited) to Earnings	145	29	(27)	(71)	49	125
Charged/(Credited) to OCI	60	–	–	–	4	64
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**

Deferred Income Tax Assets	UNUSED TAX LOSSES	RISK MANAGEMENT	OTHER	TOTAL
As at December 31, 2012	(309)	(5)	(179)	(493)
Charged/(Credited) to Earnings	218	(30)	(69)	119
Charged/(Credited) to OCI	(13)	–	7	(6)
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)**

Net Deferred Income Tax Liabilities	TOTAL
Net Deferred Income Tax Liabilities as at December 31, 2012	2,560
Charged/(Credited) to Earnings	244
Charged/(Credited) to OCI	58
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**

No deferred tax liability has been recognized as at December 31, 2014 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, 2014, the Company had temporary differences of $5,793 million (2013 – $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,	2014	2013
Canada	6,153	5,425
United States	958	1,083
	7,111	6,508

As at December 31, 2014, the above tax pools included $8 million (2013 – $5 million) of Canadian non-capital losses and $140 million (2013 – $238 million) of U.S. federal net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2014 tax pools are Canadian net capital losses totaling $593 million (2013 – $561 million), which are available for carry forward to reduce future capital gains. Of these losses, $559 million are unrecognized as a deferred income tax asset as at December 31, 2014 (2013 – $561 million). Recognition is dependent on the level of future capital gains.

10. PER SHARE AMOUNTS

A) NET EARNINGS PER SHARE

For the years ended December 31,	2014	2013	2012
Net Earnings – Basic and Diluted *($ millions)*	**744**	662	995
Basic – Weighted Average Number of Shares *(millions)*	**756.9**	755.9	755.6
Dilutive Effect of Cenovus TSARs	**0.7**	1.6	2.9
Dilutive Effect of Cenovus NSRs	**–**	–	–
Diluted – Weighted Average Number of Shares	**757.6**	757.5	758.5
Net Earnings Per Common Share *($)*			
Basic	**$0.98**	$0.88	$1.32
Diluted	**$0.98**	$0.87	$1.31

B) DIVIDENDS PER SHARE

The Company paid dividends of $805 million or $1.0648 per share for the year ended December 31, 2014 (2013 – $732 million, $0.968 per share; 2012 – $665 million, $0.88 per share). The Cenovus Board of Directors declared a first quarter dividend of $0.2662 per share, payable on March 31, 2015, to common shareholders of record as of March 13, 2015.

11. CASH AND CASH EQUIVALENTS

As at December 31,	2014	2013
Cash	**458**	363
Short-Term Investments	**425**	2,089
	883	2,452

12. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	2014	2013
Accruals	**1,417**	1,585
Partner Advances	**44**	153
Prepaids and Deposits	**56**	55
Joint Operations Receivables	**18**	26
Other	**47**	55
	1,582	1,874

13. INVENTORIES

As at December 31,	2014	2013
Product		
Refining and Marketing	**972**	1,047
Oil Sands	**182**	156
Conventional	**28**	17
Parts and Supplies	**42**	39
	1,224	1,259

During the year ended December 31, 2014, approximately $15,065 million of produced and purchased inventory was recorded as an expense (2013 – $13,895 million; 2012 – $12,363 million).

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

14. EXPLORATION AND EVALUATION ASSETS

COST	
As at December 31, 2012	1,285
Additions	331
Transfers to PP&E *(Note 15)*	(95)
Exploration Expense	(50)
Divestitures	(17)
Change in Decommissioning Liabilities	19
As at December 31, 2013	1,473
Additions	279
Transfers to PP&E *(Note 15)*	(53)
Exploration Expense	(86)
Divestitures	(2)
Change in Decommissioning Liabilities	14
As at December 31, 2014	**1,625**

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

Additions to E&E assets for the year ended December 31, 2014 include $51 million of internal costs directly related to the evaluation of these projects (2013 – $60 million). No borrowing costs or costs classified as general and administrative expenses have been capitalized during the year ended December 31, 2014 (2013 – $nil).

For the year ended December 31, 2014, $53 million of E&E assets were transferred to PP&E – development and production assets following the determination of technical feasibility and commercial viability of the projects (2013 – $95 million).

IMPAIRMENT

The impairment of E&E assets and any subsequent reversal of such impairment losses are recorded in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. For the year ended December 31, 2014, $82 million of previously capitalized E&E costs related to exploration assets within the Northern Alberta CGU were deemed not to be technically feasible and commercially viable and were recorded as exploration expense in the Conventional segment. In addition, $4 million of costs related to the expiry of leases in the Borealis CGU were recorded as exploration expense in the Oil Sands segment.

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.

15. PROPERTY, PLANT AND EQUIPMENT, NET

	UPSTREAM ASSETS				
	DEVELOPMENT & PRODUCTION	OTHER UPSTREAM	REFINING EQUIPMENT	OTHER [1]	TOTAL
COST					
As at December 31, 2012	27,003	238	3,399	767	31,407
Additions	2,702	48	106	82	2,938
Transfers from E&E Assets *(Note 14)*	95	–	–	–	95
Transfers to Assets Held for Sale	(450)	–	–	–	(450)
Change in Decommissioning Liabilities	40	–	(1)	–	39
Exchange Rate Movements and Other	–	–	150	–	150
As at December 31, 2013	29,390	286	3,654	849	34,179
Additions [2]	2,522	43	162	63	2,790
Transfers from E&E Assets *(Note 14)*	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**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2012	14,390	158	311	396	15,255
Depreciation, Depletion and Amortization	1,522	35	138	79	1,774
Transfers to Assets Held for Sale	(180)	–	–	–	(180)
Impairment Losses	59	–	–	–	59
Exchange Rate Movements and Other	–	–	(63)	–	(63)
As at December 31, 2013	15,791	193	386	475	16,845
Depreciation, Depletion and Amortization	1,602	40	156	83	1,881
Transfers to Assets Held for Sale	(27)	–	–	–	(27)
Impairment Losses	65	–	–	–	65
Exchange Rate Movements and Other	38	–	42	–	80
Divestitures	(316)	–	–	–	(316)
As at December 31, 2014	**17,153**	**233**	**584**	**558**	**18,528**
CARRYING VALUE					
As at December 31, 2012	12,613	80	3,088	371	16,152
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**

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

Additions to development and production assets include internal costs directly related to the development and construction of crude oil and natural gas properties of $216 million (2013 – $204 million). All of the Company's development and production assets are located within Canada. No borrowing costs or costs classified as general and administrative expenses have been capitalized during the year ended December 31, 2014 (2013 – $nil).

PP&E includes the following amounts in respect of assets under construction and are not subject to DD&A:

As at December 31,	2014	2013
Development and Production	478	225
Refining Equipment	159	97
	637	322

IMPAIRMENT

The impairment of PP&E and any subsequent reversal of such impairment losses are recorded in DD&A in the Consolidated Statements of Earnings and Comprehensive Income.

DD&A expense includes impairment losses as follows:

For the years ended December 31,	2014	2013	2012
Development and Production	65	59	–
Refining Equipment	–	–	–
	65	59	–

In the fourth quarter of 2014, the Company impaired equipment for $52 million. The Company does not have future plans for the equipment and does not believe it will recover the carrying amount through a sale. The asset has been written down to fair value less costs of disposal. In the second quarter of 2014, a minor natural gas property was shut-in and abandonment commenced. These impairments have been recorded in DD&A 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 DD&A in the Conventional segment.

16. DIVESTITURES

In the third quarter of 2014, the Company completed the sale of certain Wainwright properties to an unrelated third party for net proceeds of $234 million. A gain of $137 million was recorded on the sale. These assets, related liabilities and results of operations were reported in the Conventional segment.

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

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, related liabilities 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.

17. OTHER ASSETS

As at December 31,	2014	2013
Equity Investments	36	32
Long-Term Receivables	7	11
Prepaids	7	7
Other	20	18
	70	68

18. GOODWILL

As at December 31,	2014	2013
Carrying Value, Beginning of Year	739	739
Impairment	(497)	–
Carrying Value, End of Year	**242**	739

There were no additions to goodwill during the years ended December 31, 2014 and 2013.

IMPAIRMENT TEST FOR CGUs CONTAINING GOODWILL

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. All of the Company's goodwill arose in 2002 upon the formation of the predecessor corporation. The carrying amount of goodwill allocated to the Company's exploration and production CGUs is:

As at December 31,	2014	2013
Primrose (Foster Creek)	242	242
Northern Alberta	–	497
	242	739

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 and Comprehensive Income. The Northern Alberta CGU includes the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage. 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 forecast 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.

There were no impairments of goodwill in the year ended December 31, 2013 (2012 – $393 million).

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 impairment of the Northern Alberta CGU:

	ONE PERCENT INCREASE IN THE DISCOUNT RATE	FIVE PERCENT DECREASE IN THE FORWARD PRICE ESTIMATES
Impairment of Goodwill	–	–
Impairment of PP&E	134	419

19. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	2014	2013
Accruals	2,057	2,317
Partner Advances	218	233
Trade	51	102
Employee Long-Term Incentives	91	116
Interest	61	82
Other	110	87
	2,588	2,937

20. PARTNERSHIP CONTRIBUTION PAYABLE

Through its interests in WRB, Cenovus's Consolidated Balance Sheets include a Partnership Contribution Payable, which arose when Cenovus became a 50 percent partner of an integrated North American oil business. On March 28, 2014, Cenovus repaid the remaining principal and accrued interest due under the Partnership Contribution Payable.

21. LONG-TERM DEBT

As at December 31,		2014	2013
Revolving Term Debt [(1)]	A	–	–
U.S. Dollar Denominated Unsecured Notes	B	5,510	5,052
Total Debt Principal	C	5,510	5,052
Debt Discounts and Transaction Costs	D	(52)	(55)
		5,458	4,997

(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, 2014 was 5.0 percent (2013 – 5.2 percent).

A) REVOLVING TERM DEBT

As at December 31, 2014, Cenovus had in place a committed credit facility in the amount of $3.0 billion or the equivalent amount in U.S. dollars. The committed credit facility was renegotiated in November 2014 to extend the maturity date to November 30, 2018. The maturity date is extendable from time to time, for a period of up to four years 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, 2014, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2013 – $nil).

B) UNSECURED NOTES

Unsecured notes are composed of:

As at	US$ PRINCIPAL AMOUNT	DECEMBER 31, 2014	DECEMBER 31, 2013
5.70% due October 15, 2019	1,300	1,508	1,382
3.00% due August 15, 2022	500	580	532
3.80% due September 15, 2023	450	522	479
6.75% due November 15, 2039	1,400	1,624	1,489
4.45% due September 15, 2042	750	870	798
5.20% due September 15, 2043	350	406	372
		5,510	5,052

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, 2014, 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, 2014, 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, 2014, 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
2015	–	–	–
2016	–	–	–
2017	–	–	–
2018	–	–	–
2019	1,300	–	1,508
Thereafter	3,450	–	4,002
	4,750	–	5,510

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 2014, additional transaction costs of $2 million were recorded (2013 – $15 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 and refining facilities. The aggregate carrying amount of the obligation is:

As at December 31,	2014	2013
Decommissioning Liabilities, Beginning of Year	2,370	2,315
Liabilities Incurred	48	45
Liabilities Settled	(93)	(76)
Liabilities Divested	(60)	–
Transfers and Reclassifications	(9)	(26)
Change in Estimated Future Cash Flows	115	414
Change in Discount Rate	122	(401)
Unwinding of Discount on Decommissioning Liabilities	120	97
Foreign Currency Translation	3	2
Decommissioning Liabilities, End of Year	2,616	2,370

The undiscounted amount of estimated future cash flows required to settle the obligation is $8,333 million (December 31, 2013 – $7,471 million), which has been discounted using a credit-adjusted risk-free rate of 4.9 percent (December 31, 2013 – 5.2 percent). 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 $50 million to $100 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from accelerated timing of forecast abandonment and reclamation spending, and higher cost estimates.

SENSITIVITIES

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

	2014		2013	
As at December 31,	CREDIT-ADJUSTED RISK-FREE RATE	INFLATION RATE	CREDIT-ADJUSTED RISK-FREE RATE	INFLATION RATE
One Percent Increase	(419)	574	(345)	472
One Percent Decrease	562	(433)	461	(357)

23. OTHER LIABILITIES

As at December 31,	2014	2013
Deferred Revenues	–	25
Employee Long-Term Incentives	57	67
Pension and OPEB *(Note 24)*	84	51
Other	31	37
	172	180

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, 2013 and the next required actuarial valuation will be as at December 31, 2016.

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,	2014	2013	2014	2013
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	148	134	18	20
Current Service Costs	15	17	2	2
Interest Costs (1)	7	6	1	1
Benefits Paid	(3)	(5)	–	–
Plan Participant Contributions	3	2	–	–
Remeasurements:				
(Gains) Losses from Experience Adjustments	–	1	–	–
(Gains) Losses from Changes in Demographic Assumptions	(1)	12	–	(1)
(Gains) Losses from Changes in Financial Assumptions	31	(19)	2	(4)
Defined Benefit Obligation, End of Year	200	148	23	18
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	115	94	–	–
Employer Contributions	12	15	–	–
Plan Participant Contributions	3	2	–	–
Benefits Paid	(3)	(5)	–	–
Interest Income (1)	4	2	–	–
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	8	7	–	–
Fair Value of Plan Assets, End of Year	139	115	–	–
Pension and Other Post-Employment Benefit (Liability) (2)	(61)	(33)	(23)	(18)

(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 17 years and 13 years, respectively.

B) PENSION AND OPEB COSTS

For the years ended December 31,	Pension Benefits 2014	Pension Benefits 2013	Pension Benefits 2012	OPEB 2014	OPEB 2013	OPEB 2012
Defined Benefit Plan Cost:						
Current Service Costs	**15**	17	10	**2**	2	2
Past Service Costs [1]	**–**	–	18	**–**	–	–
Net Interest Costs	**3**	4	1	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**(8)**	(7)	(1)	**–**	–	–
(Gains) Losses from Experience Adjustments	**–**	1	3	**–**	–	1
(Gains) Losses from Changes in Demographic Assumptions	**(1)**	12	–	**–**	(1)	(1)
(Gains) Losses from Changes in Financial Assumptions	**31**	(19)	4	**2**	(4)	(2)
Defined Benefit Plan Cost (Gain)	**40**	8	35	**5**	(2)	1
Defined Contribution Plan Cost	**30**	27	25	**–**	–	–
Total Plan Cost	**70**	35	60	**5**	(2)	1

(1) Past service costs for eligible employees meeting certain criteria who elected to convert from the defined contribution pension to defined benefit pension.

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

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,	2014	2013
Equity Securities		
Equity Funds and Balanced Funds	**75**	67
Other	**9**	8
Bond Funds	**36**	25
Non-Invested Assets	**15**	12
Real Estate	**4**	3
	139	115

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, 2013, 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, 2015 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,	**2014**	2013	2012	**2014**	2013	2012
Discount Rate	**3.75%**	4.75%	4.00%	**3.75%**	4.75%	4.00%
Future Salary Growth Rate	**4.32%**	4.39%	4.39%	**5.65%**	5.65%	5.77%
Average Longevity *(Years)*	**88.3**	88.5	86.1	**88.3**	88.5	86.1
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**7.00%**	7.00%	8.00%

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 as at December 31, 2014 is shown below.

	ONE PERCENTAGE POINT INCREASE	ONE PERCENTAGE POINT DECREASE
Discount Rate	(34)	43
Future Salary Growth Rate	4	(4)
Health Care Cost Trend Rate	2	(2)
Future Mortality Rate *(Years)*	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, subject to certain conditions, an unlimited number of first preferred and second preferred 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

	2014		2013	
As at December 31,	NUMBER OF COMMON SHARES *(Thousands)*	AMOUNT	NUMBER OF COMMON SHARES *(Thousands)*	AMOUNT
Outstanding, Beginning of Year	**756,046**	**3,857**	755,843	3,829
Common Shares Issued Under Stock Option Plans	**1,057**	**32**	970	31
Common Shares Cancelled	**–**	**–**	(767)	(3)
Outstanding, End of Year	**757,103**	**3,889**	756,046	3,857

During 2013, the Company cancelled 767,327 common shares. The common shares were held in reserve for un-exchanged shares of Alberta Energy Company Ltd., pursuant to the merger of Alberta Energy Company Ltd. and PanCanadian Energy Corporation in 2002 ("AEC Merger"), in which Encana Corporation ("Encana") was formed. Due to the plan of arrangement ("Arrangement"), whereby Encana was split on December 1, 2009 into two independent energy companies, Encana and Cenovus, common shares of the Company were held in reserve until the tenth anniversary of the AEC Merger.

There were no preferred shares outstanding as at December 31, 2014 (2013 – nil).

As at December 31, 2014, there were 13 million (2013 – 24 million) common shares available for future issuance under stock option plans.

The Company has a dividend reinvestment plan ("DRIP"). Under the DRIP, 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 or purchased on the market.

C) PAID IN SURPLUS

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

	PRE-ARRANGEMENT EARNINGS	STOCK-BASED COMPENSATION	TOTAL
As at December 31, 2012	4,083	71	4,154
Stock-Based Compensation Expense	–	62	62
Common Shares Cancelled	3	–	3
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**

26. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

As at December 31, 2014	DEFINED BENEFIT PLAN	FOREIGN CURRENCY TRANSLATION	AVAILABLE FOR SALE INVESTMENTS	TOTAL
Balance, Beginning of Year	(12)	212	10	210
Other Comprehensive Income (Loss), Before Tax	(24)	215	–	191
Income Tax	6	–	–	6
Balance, End of Year	(30)	427	10	407

As at December 31, 2013	DEFINED BENEFIT PLAN	FOREIGN CURRENCY TRANSLATION	AVAILABLE FOR SALE INVESTMENTS	TOTAL
Balance, Beginning of Year	(26)	95	–	69
Other Comprehensive Income (Loss), Before Tax	18	117	13	148
Income Tax	(4)	–	(3)	(7)
Balance, End of Year	(12)	212	10	210

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 granted prior to February 17, 2010 expire after five years while options granted on or after February 17, 2010 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.

As at December 31, 2014	ISSUED	TERM *(Years)*	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE *(Years)*	WEIGHTED AVERAGE EXERCISE PRICE *($)*	CLOSING SHARE PRICE *($)*	NUMBER OF UNITS OUTSTANDING *(Thousands)*
NSRs	On or After February 24, 2011	7	5.13	32.63	23.97	40,549
TSARs	Prior to February 17, 2010	5	0.07	25.58	23.97	21
TSARs	On or After February 17, 2010	7	2.20	26.72	23.97	3,841

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2014 was $4.70 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	1.62%
Expected Dividend Yield	3.18%
Expected Volatility (1)	25.80%
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, 2014	NUMBER OF NSRs *(Thousands)*	WEIGHTED AVERAGE EXERCISE PRICE *($)*
Outstanding, Beginning of Year	26,315	35.26
Granted	16,307	28.59
Exercised	(125)	32.24
Forfeited	(1,948)	34.31
Outstanding, End of Year	40,549	32.63
Exercisable, End of Year	13,439	36.18

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $34.06.

	OUTSTANDING NSRs		
As at December 31, 2014 *Range of Exercise Price ($)*	NUMBER OF NSRs *(Thousands)*	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE *(Years)*	WEIGHTED AVERAGE EXERCISE PRICE *($)*
20.00 to 24.99	55	6.94	23.81
25.00 to 29.99	15,181	6.14	28.39
30.00 to 34.99	13,564	5.17	32.60
35.00 to 39.99	11,749	3.79	38.18
	40,549	5.13	32.63

	EXERCISABLE NSRs	
As at December 31, 2014 *Range of Exercise Price ($)*	NUMBER OF NSRs *(Thousands)*	WEIGHTED AVERAGE EXERCISE PRICE *($)*
20.00 to 24.99	–	–
25.00 to 29.99	85	29.32
30.00 to 34.99	4,515	32.66
35.00 to 39.99	8,839	38.04
	13,439	36.18

TSARs

The Company has recorded a liability of $8 million as at December 31, 2014 (December 31, 2013 – $33 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	1.43%
Expected Dividend Yield	3.51%
Expected Volatility [1]	26.52%
Cenovus's Common Share Price	23.97

(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, 2014 was $nil (December 31, 2013 – $27 million).

The following tables summarize information related to the TSARs held by Cenovus employees:

As at December 31, 2014	NUMBER OF TSARs *(Thousands)*	WEIGHTED AVERAGE EXERCISE PRICE *($)*
Outstanding, Beginning of Year	7,086	26.56
Exercised for Cash Payment	(2,106)	26.34
Exercised as Options for Common Shares	(1,044)	26.38
Forfeited	(13)	28.66
Expired	(61)	26.38
Outstanding, End of Year	3,862	26.72
Exercisable, End of Year	3,862	26.72

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $30.14.

	OUTSTANDING TSARs		
As at December 31, 2014 *Range of Exercise Price ($)*	NUMBER OF TSARs *(Thousands)*	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE *(Years)*	WEIGHTED AVERAGE EXERCISE PRICE *($)*
20.00 to 29.99	3,703	2.12	26.46
30.00 to 39.99	159	2.98	32.86
	3,862	2.16	26.72

	EXERCISABLE TSARs	
As at December 31, 2014 *Range of Exercise Price ($)*	NUMBER OF TSARs *(Thousands)*	WEIGHTED AVERAGE EXERCISE PRICE *($)*
20.00 to 29.99	3,703	26.46
30.00 to 39.99	159	32.86
	3,862	26.72

The closing price of Cenovus's common shares on the TSX as at December 31, 2014 was $23.97.

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 $109 million as at December 31, 2014 (2013 – $103 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares as at December 31, 2014. The intrinsic value of vested PSUs was $nil as at December 31, 2014 (2013 – $nil) as PSUs are paid out upon vesting.

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

As at December 31, 2014	NUMBER OF PSUs *(Thousands)*
Outstanding, Beginning of Year	5,785
Granted	3,012
Vested and Paid Out	(1,625)
Cancelled	(328)
Units in Lieu of Dividends	255
Outstanding, End of Year	7,099

C) 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 $31 million as at December 31, 2014 (2013 – $36 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares as at December 31, 2014. 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, 2014	NUMBER OF DSUs *(Thousands)*
Outstanding, Beginning of Year	1,192
Granted to Directors	57
Granted From Annual Bonus Awards	7
Units in Lieu of Dividends	46
Redeemed	(5)
Outstanding, End of Year	1,297

D) TOTAL STOCK-BASED COMPENSATION EXPENSE (RECOVERY)

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

For the years ended December 31,	2014	2013	2012
NSRs	41	35	27
TSARs	(10)	(16)	(1)
PSUs	34	32	46
DSUs	(5)	–	3
Total Stock-Based Compensation Expense (Recovery)	60	51	75

28. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	2014	2013	2012
Salaries, Bonuses and Other Short-Term Employee Benefits	550	494	441
Defined Contribution Pension Plan	18	17	14
Defined Benefit Pension Plan and OPEB	14	15	20
Stock-Based Compensation *(Note 27)*	60	51	75
	642	577	550

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,	2014	2013	2012
Salaries, Director Fees and Short-Term Benefits	29	31	27
Post-Employment Benefits	4	4	7
Stock-Based Compensation	20	24	35
	53	59	69

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 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 excluding any amounts with respect to the Partnership Contribution Payable. Cenovus's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

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

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

As at December 31,	2014	2013
Long-Term Debt	5,458	4,997
Shareholders' Equity	10,186	9,946
Capitalization	15,644	14,943
Debt to Capitalization	35%	33%

Cenovus continues to target a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times over the long-term.

As at December 31,	2014	2013	2012
Debt	5,458	4,997	4,679
Net Earnings	744	662	995
Add (Deduct):			
Finance Costs	445	529	455
Interest Income	(33)	(96)	(109)
Income Tax Expense	451	432	783
Depreciation, Depletion and Amortization	1,946	1,833	1,585
Goodwill Impairment	497	–	393
E&E Impairment	86	50	68
Unrealized (Gain) Loss on Risk Management	(596)	415	(57)
Foreign Exchange (Gain) Loss, Net	411	208	(20)
(Gain) Loss on Divestitures of Assets	(156)	1	–
Other (Income) Loss, Net	(4)	2	(5)
Adjusted EBITDA	3,791	4,036	4,088
Debt to Adjusted EBITDA	1.4x	1.2x	1.1x

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

As at December 31, 2014, Cenovus had $3.0 billion available on its committed credit facility. In addition, Cenovus had in place a $1.5 billion Canadian base shelf prospectus and a US$2.0 billion U.S. base shelf prospectus, the availability of which are dependent on market conditions.

As at December 31, 2014, 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, Partnership Contribution Payable, risk management assets and liabilities, long-term receivables, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) FAIR VALUE OF NON-DERIVATIVE FINANCIAL INSTRUMENTS

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

The fair values of the Partnership Contribution Payable and 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, 2014, the carrying value of Cenovus's long-term debt was $5,458 million and the fair value was $5,726 million (2013 carrying value – $4,997 million, fair value – $5,388 million).

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

As at December 31,	2014	2013
Fair Value, Beginning of Year	32	14
Acquisition of Investments	4	5
Reclassification of Equity Investments	(4)	–
Change in Fair Value [(1)]	–	13
Fair Value, End of Year	32	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, natural gas and power purchase contracts. Crude oil and natural gas contracts are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. The forward prices used in the determination of the fair value of the power purchase contracts as at December 31, 2014 range from $33.50 to $54.75 per Megawatt Hour.

SUMMARY OF UNREALIZED RISK MANAGEMENT POSITIONS

	DECEMBER 31, 2014			DECEMBER 31, 2013		
As at	ASSET	RISK MANAGEMENT LIABILITY	NET	ASSET	RISK MANAGEMENT LIABILITY	NET
Commodity Prices						
Crude Oil	423	7	416	10	136	(126)
Natural Gas	55	–	55	–	–	–
Power	–	9	(9)	–	3	(3)
Total Fair Value	478	16	462	10	139	(129)

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

As at December 31,	2014	2013
Prices Sourced From Observable Data or Market Corroboration *(Level 2)*	471	(126)
Prices Determined From Unobservable Inputs *(Level 3)*	(9)	(3)
	462	(129)

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,	2014	2013
Fair Value of Contracts, Beginning of Year	(129)	270
Fair Value of Contracts Realized During the Year (1)	(66)	(122)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year (1)	662	(293)
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	(5)	16
Fair Value of Contracts, End of Year	462	(129)

(1) Includes a realized gain of $4 million and a decrease in fair value of $10 million related to the power contracts.

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:

As at	DECEMBER 31, 2014 ASSET	DECEMBER 31, 2014 RISK MANAGEMENT LIABILITY	DECEMBER 31, 2014 NET	DECEMBER 31, 2013 ASSET	DECEMBER 31, 2013 RISK MANAGEMENT LIABILITY	DECEMBER 31, 2013 NET
Recognized Risk Management Positions						
Gross Amount	479	17	462	16	145	(129)
Amount Offset	(1)	(1)	–	(6)	(6)	–
Net Amount per Consolidated Financial Statements	478	16	462	10	139	(129)

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, 2014, $12 million (2013 – $10 million) was pledged as collateral, of which $7 million (2013 – $5 million) could have been withdrawn.

C) EARNINGS IMPACT OF (GAINS) LOSSES FROM RISK MANAGEMENT POSITIONS

For the years ended December 31,	2014	2013	2012
Realized (Gain) Loss (1)	(66)	(122)	(336)
Unrealized (Gain) Loss (2)	(596)	415	(57)
(Gain) Loss on Risk Management	(662)	293	(393)

(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 future 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 and condensate supply used for blending. Cenovus has entered into a limited number of swaps and futures to help protect against widening light/heavy crude oil price differentials.

Natural Gas – To partially mitigate the natural gas commodity price risk, the Company has entered into swaps, which fix the AECO 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 COMMODITY PRICE POSITIONS AS AT DECEMBER 31, 2014

As at December 31, 2014	NOTIONAL VOLUMES	TERM	AVERAGE PRICE	FAIR VALUE
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	18,000 bbls/d	2015	$113.75/bbl	269
Brent Fixed Price	1,000 bbls/d	January – June 2015	$100.25/bbl	5
Brent Fixed Price	6,000 bbls/d	January – June 2015	US$65.03/bbl	6
WCS Differential (1)	5,000 bbls/d	January – June 2015	US$(19.85)/bbl	(2)
Brent Collars	10,000 bbls/d	2015	$105.25 – $123.57/bbl	121
Other Financial Positions (2)				17
Crude Oil Fair Value Position				416
Natural Gas Contracts				
Fixed Price Contracts				
AECO Fixed Price	149 MMcf/d	2015	$3.86/Mcf	55
Natural Gas Fair Value Position				55
Power Purchase Contracts				
Power Fair Value Position				(9)

(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.

COMMODITY PRICE SENSITIVITIES – RISK MANAGEMENT POSITIONS

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

Risk Management Positions in Place as at December 31, 2014

COMMODITY	SENSITIVITY RANGE	INCREASE	DECREASE
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(145)	146
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	5	(5)
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)

Risk Management Positions in Place as at December 31, 2013

COMMODITY	SENSITIVITY RANGE	INCREASE	DECREASE
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(200)	200
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges Tied to Production	31	(31)
Natural Gas Commodity Price	± US$1 per Mcf Applied to NYMEX and AECO Natural Gas Hedges	–	–
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	19	(19)

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 8, 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, 2014, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2013 – US$4,750 million) and US$nil related to the U.S. dollar Partnership Contribution Receivable (2013 – US$nil). In respect of these financial instruments, the impact of a $0.01 change 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,	2014	2013	2012
$0.01 Increase in Foreign Exchange Rate	48	48	30
$0.01 Decrease in Foreign Exchange Rate	(48)	(48)	(30)

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.

As at December 31, 2014, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2013 – $nil; 2012 – $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, 2014 and 2013, substantially all of the Company's accounts receivable were less than 60 days. As at December 31, 2014, 91 percent (2013 – 94 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, 2014, Cenovus had two counterparties (2013 – four 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. 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. It is Cenovus's intention to maintain investment grade credit ratings on its senior unsecured debt.

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, commercial paper and availability under its shelf prospectuses. As at December 31, 2014, Cenovus had $3.0 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:

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**

2013	LESS THAN 1 YEAR	1-3 YEARS	4-5 YEARS	THEREAFTER	TOTAL
Accounts Payable and Accrued Liabilities	2,937	–	–	–	2,937
Risk Management Liabilities (1)	136	3	–	–	139
Long-Term Debt (2)	271	537	537	8,732	10,077
Partnership Contribution Payable (2)	520	1,040	130	–	1,690
Other (2)	–	6	2	4	12

(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,	2014	2013	2012
Interest Paid	**335**	409	342
Interest Received	**33**	119	113
Income Taxes Paid	**46**	133	304

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:

2014	1 YEAR	2 YEARS	3 YEARS	4 YEARS	5 YEARS	THEREAFTER	TOTAL
Pipeline Transportation (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**

2013	1 YEAR	2 YEARS	3 YEARS	4 YEARS	5 YEARS	THEREAFTER	TOTAL
Pipeline Transportation (1)	377	554	647	807	1,284	17,512	21,181
Operating Leases (Building Leases)	119	119	117	118	159	2,950	3,582
Product Purchases	98	20	7	–	–	–	125
Capital Commitments	52	36	30	9	21	27	175
Other Long-Term Commitments	50	40	21	17	12	116	256
Total Payments (2)	696	769	822	951	1,476	20,605	25,319
Fixed Price Product Sales	52	54	56	3	–	–	165

(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.

As at December 31, 2014, there were outstanding letters of credit aggregating $74 million issued as security for performance under certain contracts (2013 – $78 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 $2,616 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	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Gross Sales										
Upstream	**8,261**	1,721	2,147	2,295	2,098	6,892	1,767	1,926	1,646	1,553
Refining and Marketing	**12,658**	2,773	3,144	3,483	3,258	12,706	3,223	3,459	3,078	2,946
Corporate and Eliminations	**(812)**	(156)	(197)	(218)	(241)	(605)	(163)	(190)	(130)	(122)
Less: Royalties	**465**	100	124	138	103	336	80	120	78	58
Revenues	**19,642**	4,238	4,970	5,422	5,012	18,657	4,747	5,075	4,516	4,319

OPERATING CASH FLOW	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids										
Foster Creek	**965**	228	297	227	213	877	204	252	232	189
Christina Lake	**1,051**	237	308	291	215	596	179	248	96	73
Pelican Lake	**403**	80	111	119	93	385	92	130	96	67
Other Conventional	**957**	193	241	269	254	1,003	232	285	251	235
Natural Gas	**553**	111	129	162	151	437	110	94	118	115
Other Upstream Operations	**18**	12	–	8	(2)	27	8	5	8	6
	3,947	861	1,086	1,076	924	3,325	825	1,014	801	685
Refining and Marketing	**211**	(322)	68	220	245	1,143	151	139	324	529
Operating Cash Flow (1)	**4,158**	539	1,154	1,296	1,169	4,468	976	1,153	1,125	1,214

CASH FLOW	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Cash from Operating Activities	**3,526**	868	1,092	1,109	457	3,539	976	840	828	895
Deduct (Add back):										
Net Change in Other Assets and Liabilities	**(135)**	(38)	(28)	(27)	(42)	(120)	(30)	(25)	(31)	(34)
Net Change in Non-Cash Working Capital	**182**	505	135	(53)	(405)	50	171	(67)	(12)	(42)
Cash Flow (2)	**3,479**	401	985	1,189	904	3,609	835	932	871	971
Per Share – Basic	**4.60**	0.53	1.30	1.57	1.20	4.77	1.10	1.23	1.15	1.28
– Diluted	**4.59**	0.53	1.30	1.57	1.19	4.76	1.10	1.23	1.15	1.28

EARNINGS	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Operating Earnings (Loss) (3)	**633**	(590)	372	473	378	1,171	212	313	255	391
Per Share – Diluted	**0.84**	(0.78)	0.49	0.62	0.50	1.55	0.28	0.41	0.34	0.52
Net Earnings (Loss)	**744**	(472)	354	615	247	662	(58)	370	179	171
Per Share – Basic	**0.98**	(0.62)	0.47	0.81	0.33	0.88	(0.08)	0.49	0.24	0.23
– Diluted	**0.98**	(0.62)	0.47	0.81	0.33	0.87	(0.08)	0.49	0.24	0.23

(1) Operating cash flow is a non-GAAP measure defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of operating cash flow.

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

(3) Operating earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating earnings is defined as earnings before income tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on operating earnings.

TAX AND EXCHANGE RATES

	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Effective Tax Rates Using:										
Net Earnings	**37.7%**					39.5%				
Operating Earnings, Excluding Divestitures	**29.7%**					31.4%				
Canadian Statutory Rate	**25.2%**					25.2%				
U.S. Statutory Rate	**38.1%**					38.5%				
Foreign Exchange Rates *(US$ per C$1)*										
Average	**0.905**	0.881	0.918	0.917	0.906	0.971	0.953	0.963	0.977	0.992
Period End	**0.862**	0.862	0.892	0.937	0.905	0.940	0.940	0.972	0.951	0.985

FINANCIAL METRICS *(Non-GAAP measures)*

	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Debt to Capitalization (1), (2)	**35%**	35%	33%	33%	36%	33%	33%	32%	33%	33%
Net Debt to Capitalization (1), (3)	**31%**	31%	28%	30%	32%	29%	29%	28%	30%	28%
Debt to Adjusted EBITDA (2), (4)	**1.4x**	1.4x	1.3x	1.2x	1.4x	1.2x	1.2x	1.2x	1.2x	1.1x
Net Debt to Adjusted EBITDA (3), (4)	**1.2x**	1.2x	1.0x	1.1x	1.2x	1.0x	1.0x	1.0x	1.0x	0.9x
Return on Capital Employed (5)	**6%**	6%	9%	9%	7%	6%	6%	6%	5%	7%
Return on Common Equity (6)	**7%**	7%	11%	12%	7%	7%	7%	6%	5%	8%

(1) Capitalization is a non-GAAP measure defined as debt plus shareholders' equity.
(2) Debt includes the Company's short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable.
(3) 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 and the current and long-term portions of the Partnership Contribution Receivable.
(4) We define Adjusted EBITDA 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 12-month basis.
(5) Return on capital employed is calculated, on a trailing 12-month basis, as net earnings before after-tax interest divided by average shareholders' equity plus average debt.
(6) Return on common equity is calculated, on a trailing 12-month basis, as net earnings divided by average shareholders' equity.

COMMON SHARE INFORMATION

	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*										
Period End	**757.1**	757.1	757.1	757.0	756.9	756.0	756.0	755.8	755.8	755.8
Average – Basic	**756.9**	757.1	757.1	756.9	756.4	755.9	755.9	755.8	755.8	756.0
Average – Diluted	**757.6**	757.1	758.8	758.0	757.3	757.5	757.2	757.2	757.1	758.4
Price Range *($ per share)*										
TSX – C$										
High	**34.79**	30.13	34.79	34.70	32.02	34.13	31.69	32.77	32.08	34.13
Low	**18.72**	18.72	29.77	30.80	28.25	28.32	29.33	28.98	28.32	31.09
Close	**23.97**	23.97	30.13	34.59	31.97	30.40	30.40	30.74	30.00	31.46
NYSE – US$										
High	**32.64**	26.89	32.64	32.44	28.96	34.50	30.34	31.60	31.58	34.50
Low	**16.11**	16.11	26.57	28.35	25.52	27.25	27.60	28.00	27.25	30.58
Close	**20.62**	20.62	26.88	32.37	28.96	28.65	28.65	29.85	28.52	30.99
Dividends Paid *($ per share)*	**$1.0648**	$0.2662	$0.2662	$0.2662	$0.2662	$0.968	$0.242	$0.242	$0.242	$0.242
Share Volume Traded *(millions)*	**803.8**	333.1	147.7	152.7	170.3	685.7	146.2	183.0	201.6	154.9

NET CAPITAL INVESTMENT

($ millions)	2014 YEAR	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 YEAR	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Capital Investment										
Oil Sands										
Foster Creek	**796**	159	207	209	221	797	193	205	189	210
Christina Lake	**794**	231	198	183	182	688	189	162	162	175
Total	**1,590**	390	405	392	403	1,485	382	367	351	385
Other Oil Sands	**396**	104	89	79	124	400	120	59	69	152
	1,986	494	494	471	527	1,885	502	426	420	537
Conventional										
Pelican Lake	**246**	46	61	68	71	463	115	97	111	140
Other Conventional	**594**	173	137	85	199	726	216	178	134	198
	840	219	198	153	270	1,189	331	275	245	338
Refining and Marketing	**163**	52	42	46	23	107	37	19	26	25
Corporate	**62**	21	16	16	9	81	28	23	15	15
Capital Investment	**3,051**	786	750	686	829	3,262	898	743	706	915
Acquisitions [1]	**18**	1	–	16	1	32	27	1	1	3
Divestitures	**(277)**	(1)	(235)	(39)	(2)	(283)	(41)	(241)	–	(1)
Net Acquisition and Divestiture Activity	**(259)**	–	(235)	(23)	(1)	(251)	(14)	(240)	1	2
Net Capital Investment	**2,792**	786	515	663	828	3,011	884	503	707	917

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

OPERATING STATISTICS – BEFORE ROYALTIES

UPSTREAM PRODUCTION VOLUMES

	2014 YEAR	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 YEAR	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*										
Oil Sands – Heavy Oil										
Foster Creek	**59,172**	68,377	56,631	56,852	54,706	53,190	52,419	49,092	55,338	55,996
Christina Lake	**69,023**	73,836	68,458	67,975	65,738	49,310	61,471	52,732	38,459	44,351
	128,195	142,213	125,089	124,827	120,444	102,500	113,890	101,824	93,797	100,347
Conventional Liquids										
Pelican Lake – Heavy Oil	**24,924**	25,906	24,196	24,806	24,782	24,254	24,528	24,826	23,959	23,687
Other Heavy Oil	**14,622**	12,115	14,900	15,498	16,017	15,991	15,480	15,507	16,284	16,712
Light and Medium Oil	**34,531**	34,661	33,548	35,329	34,598	35,467	33,646	33,651	36,137	38,508
Natural Gas Liquids [2]	**1,221**	1,282	1,356	1,228	1,013	1,063	1,199	1,130	950	971
	75,298	73,964	74,000	76,861	76,410	76,775	74,853	75,114	77,330	79,878
Total Crude Oil and Natural Gas Liquids	**203,493**	216,177	199,089	201,688	196,854	179,275	188,743	176,938	171,127	180,225
Natural Gas *(MMcf/d)*										
Oil Sands	**22**	22	23	23	19	21	21	23	22	18
Conventional	**466**	457	466	484	457	508	493	500	514	527
Total Natural Gas	**488**	479	489	507	476	529	514	523	536	545
Total Production *(BOE/d)*	**284,826**	296,010	280,589	286,188	276,187	267,442	274,410	264,105	260,460	271,058

(2) Natural gas liquids include condensate volumes.

AVERAGE ROYALTY RATES

(excluding impact of Realized Gain (Loss) on Risk Management)

	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek	**8.8%**	11.2%	7.2%	9.3%	8.1%	5.8%	6.3%	7.6%	5.7%	2.9%
Christina Lake	**7.5%**	7.2%	7.9%	7.7%	7.1%	6.8%	7.8%	7.0%	5.6%	5.7%
Conventional										
Pelican Lake	**7.5%**	8.4%	7.1%	8.0%	6.9%	5.9%	3.2%	7.7%	5.8%	6.2%
Weyburn	**21.9%**	19.0%	24.0%	24.4%	19.4%	19.6%	16.8%	22.3%	20.3%	18.3%
Other	**5.9%**	6.7%	6.5%	5.5%	4.9%	6.5%	7.4%	6.8%	6.0%	5.7%
Natural Gas Liquids	**2.1%**	2.6%	1.6%	2.2%	2.2%	1.9%	1.9%	2.9%	2.5%	0.2%
Natural Gas	**1.9%**	2.5%	2.0%	2.0%	1.4%	1.4%	1.2%	1.8%	1.2%	1.7%

REFINING

	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Refinery Operations (1)										
Crude Oil Capacity (2) *(Mbbls/d)*	**460**	460	460	460	460	457	457	457	457	457
Crude Oil Runs *(Mbbls/d)*	**423**	420	407	466	400	442	447	464	439	416
Heavy Oil	**199**	179	201	221	195	222	221	240	230	197
Light/Medium	**224**	241	206	245	205	220	226	224	209	219
Crude Utilization	**92%**	91%	88%	101%	87%	97%	98%	101%	96%	91%
Refined Products *(Mbbls/d)*	**445**	442	429	489	420	463	469	487	457	439

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

SELECTED AVERAGE BENCHMARK PRICES

	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
Brent	**99.51**	76.98	103.39	109.77	107.90	108.76	109.35	109.71	103.35	112.65
West Texas Intermediate ("WTI")	**93.00**	73.15	97.17	102.99	98.68	97.97	97.46	105.82	94.22	94.37
Differential Brent Futures-WTI	**6.51**	3.83	6.22	6.78	9.22	10.79	11.89	3.89	9.13	18.28
Western Canadian Select ("WCS")	**73.60**	58.91	76.99	82.95	75.55	72.77	65.26	88.34	75.06	62.41
Differential – WTI-WCS	**19.40**	14.24	20.18	20.04	23.13	25.20	32.20	17.48	19.16	31.96
Condensate – (C5 @ Edmonton)	**92.95**	70.57	93.45	105.15	102.64	101.69	94.22	103.80	101.50	107.24
Differential – WTI-Condensate (premium)/discount	**0.05**	2.58	3.72	(2.16)	(3.96)	(3.72)	3.24	2.02	(7.28)	(12.87)
Refining Margins 3-2-1 Crack Spreads (3) *(US$/bbl)*										
Chicago	**17.61**	14.60	17.57	19.72	18.55	21.77	12.29	16.19	31.06	27.53
Midwest Combined (Group 3)	**16.27**	13.28	16.65	17.75	17.41	20.80	10.66	17.35	27.24	27.93
Natural Gas Prices										
AECO *($/Mcf)*	**4.42**	4.01	4.22	4.67	4.76	3.17	3.15	2.82	3.59	3.08
NYMEX *(US$/Mcf)*	**4.42**	4.00	4.06	4.67	4.94	3.65	3.60	3.58	4.09	3.34
Differential – NYMEX-AECO *(US$/Mcf)*	**0.40**	0.44	0.16	0.40	0.60	0.58	0.59	0.89	0.56	0.27

(3) 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)	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek (1) (2) *($/bbl)*										
Price	**69.43**	51.95	76.82	79.77	71.44	66.30	59.39	87.49	68.17	52.60
Royalties	**5.95**	5.67	5.40	7.14	5.71	3.73	3.56	6.31	3.87	1.47
Transportation and Blending	**1.98**	1.85	2.17	3.10	0.78	2.36	3.21	4.37	0.04	1.89
Operating	**16.55**	13.65	14.79	19.38	19.09	15.77	15.90	17.12	16.19	14.03
Netback	**44.95**	30.78	54.46	50.15	45.86	44.44	36.72	59.69	48.07	35.21
Heavy Oil – Christina Lake (1) (2) *($/bbl)*										
Price	**61.57**	47.21	67.62	72.25	59.89	51.26	44.36	74.98	52.61	33.41
Royalties	**4.40**	3.14	5.07	5.37	4.04	3.25	3.22	5.06	2.71	1.69
Transportation and Blending	**3.53**	4.14	3.75	3.14	3.02	3.55	3.29	3.16	4.45	3.67
Operating	**11.20**	9.31	10.40	12.08	13.30	12.47	10.57	11.46	16.83	12.93
Netback	**42.44**	30.62	48.40	51.66	39.53	31.99	27.28	55.30	28.62	15.12
Total Heavy Oil – Oil Sands (1) (2) *($/bbl)*										
Price	**65.18**	49.44	71.82	75.65	65.19	59.10	51.34	81.16	61.88	44.01
Royalties	**5.11**	4.33	5.22	6.17	4.80	3.50	3.37	5.68	3.40	1.57
Transportation and Blending	**2.82**	3.06	3.03	3.12	1.99	2.93	3.25	3.76	1.82	2.69
Operating	**13.66**	11.35	12.41	15.38	15.96	14.19	13.04	14.26	16.45	13.53
Netback	**43.59**	30.70	51.16	50.98	42.44	38.48	31.68	57.46	40.21	26.22
Heavy Oil – Pelican Lake (1) (2) *($/bbl)*										
Price	**76.07**	61.24	81.66	84.66	76.20	70.09	64.52	88.08	72.32	54.30
Royalties	**5.50**	4.86	5.56	6.50	5.04	4.00	1.97	6.64	4.08	3.22
Transportation and Blending	**3.18**	3.29	3.24	3.13	3.07	2.41	2.79	2.18	2.58	2.07
Operating	**21.41**	18.84	20.49	21.23	24.96	20.65	21.22	19.90	22.21	19.23
Netback	**45.98**	34.25	52.37	53.80	43.13	43.03	38.54	59.36	43.45	29.78
Heavy Oil – Other Conventional (1) (2) *($/bbl)*										
Price	**76.55**	58.31	80.74	81.09	82.14	70.65	64.58	86.58	70.81	61.62
Royalties	**9.70**	10.71	11.10	9.77	7.52	9.18	10.40	12.27	7.67	6.57
Transportation and Blending	**3.47**	3.07	3.64	3.94	3.13	2.90	2.54	3.04	2.59	3.39
Operating	**19.63**	17.09	19.29	19.74	21.81	17.34	17.54	16.32	17.38	18.04
Production and Mineral Taxes	**0.48**	0.08	0.61	0.84	0.32	0.31	0.12	0.55	0.30	0.30
Netback	**43.27**	27.36	46.10	46.80	49.36	40.92	33.98	54.40	42.87	33.32
Total Heavy Oil – Conventional (1) (2) *($/bbl)*										
Price	**76.25**	60.25	81.30	83.29	78.52	70.31	64.55	87.50	71.73	57.42
Royalties	**7.09**	6.85	7.72	7.76	6.01	6.08	5.31	8.83	5.50	4.65
Transportation and Blending	**3.29**	3.22	3.40	3.44	3.09	2.60	2.69	2.51	2.58	2.63
Operating	**20.74**	18.24	20.02	20.66	23.73	19.32	19.76	18.51	20.30	18.72
Production and Mineral Taxes	**0.18**	0.03	0.24	0.32	0.13	0.13	0.05	0.21	0.12	0.13
Netback	**44.95**	31.91	49.92	51.11	45.56	42.18	36.74	57.44	43.23	31.29
Total Heavy Oil (1) (2) *($/bbl)*										
Price	**67.83**	51.74	73.99	77.63	68.64	62.23	54.61	82.97	64.91	47.82
Royalties	**5.59**	4.87	5.79	6.58	5.12	4.22	3.85	6.58	4.05	2.45
Transportation and Blending	**2.93**	3.09	3.11	3.20	2.28	2.84	3.11	3.40	2.06	2.67
Operating	**15.35**	12.82	14.15	16.75	17.97	15.62	14.70	15.47	17.63	15.01
Production and Mineral Taxes	**0.04**	0.01	0.05	0.08	0.03	0.04	0.01	0.06	0.04	0.04
Netback	**43.92**	30.95	50.89	51.02	43.24	39.51	32.94	57.46	41.13	27.65

(1) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in 2013.
(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	**42.01**	35.45	38.50	47.28	48.35	42.41	41.85	38.85	42.60	46.00
Christina Lake	**45.45**	38.23	42.57	49.30	52.81	45.25	44.16	39.86	47.13	51.46
Heavy Oil – Oil Sands	**43.87**	36.92	40.71	48.39	50.77	43.77	43.09	39.36	44.43	48.44
Pelican Lake	**15.86**	14.70	12.64	17.55	18.30	15.59	13.58	12.09	16.74	20.31
Other Conventional Heavy Oil	**15.46**	12.58	14.20	17.94	16.40	13.12	10.05	10.96	16.68	14.73
Heavy Oil – Conventional	**15.71**	13.98	13.25	17.70	17.56	14.60	12.18	11.65	16.72	17.93
Total Heavy Oil	**37.13**	32.04	34.42	40.44	42.17	35.63	35.44	31.46	35.91	39.78

PER-UNIT RESULTS

(excluding impact of Realized Gain (Loss) on Risk Management)	2014					2013				
	YEAR	Q4	Q3	Q2	Q1	YEAR	Q4	Q3	Q2	Q1
Light and Medium Oil *($/bbl)*										
Price	**88.30**	71.10	89.85	98.27	94.18	86.30	82.12	100.64	86.84	76.77
Royalties	**9.15**	6.12	10.36	11.37	8.78	8.28	6.58	11.01	8.61	7.05
Transportation and Blending	**3.34**	2.89	3.06	3.31	4.11	4.35	5.15	4.58	4.37	3.39
Operating	**17.28**	15.84	17.40	17.45	18.47	16.23	17.26	15.06	16.32	16.26
Production and Mineral Taxes	**2.70**	2.59	2.99	2.97	2.23	2.30	1.26	2.80	2.64	2.46
Netback	**55.83**	43.66	56.04	63.17	60.59	55.14	51.87	67.19	54.90	47.61
Total Crude Oil [(1)] *($/bbl)*										
Price	**71.39**	55.05	76.64	81.35	73.15	67.05	59.41	86.41	69.75	54.02
Royalties	**6.21**	5.08	6.56	7.45	5.76	5.03	4.33	7.44	5.05	3.43
Transportation and Blending	**3.00**	3.06	3.10	3.22	2.60	3.14	3.47	3.63	2.57	2.82
Operating	**15.69**	13.34	14.70	16.87	18.06	15.74	15.15	15.39	17.34	15.27
Production and Mineral Taxes	**0.50**	0.45	0.54	0.60	0.42	0.49	0.23	0.59	0.61	0.56
Netback	**45.99**	33.12	51.74	53.21	46.31	42.65	36.23	59.36	44.18	31.94
Natural Gas Liquids *($/bbl)*										
Price	**65.55**	50.82	66.70	78.38	67.31	60.34	59.39	65.71	46.44	68.88
Royalties	**1.38**	1.34	1.07	1.70	1.48	1.13	1.14	1.92	1.17	0.12
Netback	**64.17**	49.48	65.63	76.68	65.83	59.21	58.25	63.79	45.27	68.76
Total Liquids [(1)] *($/bbl)*										
Price	**71.35**	55.02	76.57	81.33	73.12	67.01	59.41	86.28	69.61	54.10
Royalties	**6.18**	5.06	6.52	7.41	5.74	5.01	4.31	7.40	5.03	3.42
Transportation and Blending	**2.98**	3.04	3.08	3.20	2.59	3.12	3.45	3.61	2.55	2.81
Operating	**15.59**	13.25	14.60	16.77	17.96	15.65	15.06	15.29	17.24	15.19
Production and Mineral Taxes	**0.50**	0.44	0.54	0.60	0.42	0.48	0.23	0.59	0.61	0.55
Netback	**46.10**	33.23	51.83	53.35	46.41	42.75	36.36	59.39	44.18	32.13
Total Natural Gas *($/Mcf)*										
Price	**4.37**	3.89	4.22	4.87	4.47	3.20	3.21	2.83	3.50	3.25
Royalties	**0.08**	0.09	0.08	0.09	0.06	0.04	0.04	0.05	0.04	0.05
Transportation and Blending	**0.12**	0.13	0.11	0.11	0.11	0.11	0.11	0.10	0.08	0.15
Operating	**1.23**	1.21	1.24	1.23	1.26	1.16	1.23	1.13	1.16	1.14
Production and Mineral Taxes	**0.05**	0.03	0.05	0.13	(0.01)	0.02	0.02	0.03	(0.01)	0.03
Netback	**2.89**	2.43	2.74	3.31	3.05	1.87	1.81	1.52	2.23	1.88
Total [(1)] [(2)] *($/BOE)*										
Price	**58.29**	46.14	61.85	65.71	59.68	51.23	47.23	63.12	52.55	42.52
Royalties	**4.53**	3.80	4.79	5.36	4.19	3.44	3.07	5.02	3.35	2.38
Transportation and Blending	**2.32**	2.40	2.39	2.45	2.03	2.31	2.60	2.60	1.82	2.17
Operating	**13.22**	11.57	12.53	13.95	14.94	12.79	12.73	12.44	13.64	12.39
Production and Mineral Taxes	**0.44**	0.36	0.48	0.65	0.28	0.36	0.19	0.45	0.38	0.42
Netback	**37.78**	28.01	41.66	43.30	38.24	32.33	28.64	42.61	33.36	25.16
Impact of Long-Term Incentives Costs (Recovery) on Total Operating Costs *($/BOE)*	**0.16**	(0.09)	0.08	0.36	0.29	0.12	0.06	0.23	0.07	0.10
Impact of Realized Gain (Loss) on Risk Management										
Liquids *($/bbl)*	**0.50**	7.06	(0.45)	(2.94)	(2.00)	1.09	2.77	(2.02)	0.72	2.62
Natural Gas *($/Mcf)*	**0.04**	0.05	0.11	(0.02)	–	0.32	0.36	0.38	0.18	0.39
Total [(2)] *($/BOE)*	**0.42**	5.17	(0.13)	(2.09)	(1.42)	1.37	2.58	(0.58)	0.84	2.52

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

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

ADDITIONAL RESERVES *and* OIL AND GAS INFORMATION

For information in relation to the presentation of our reserves data and other oil and gas information, see "Oil and Gas Reserves and Resources" in our MD&A and "Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2014 ("AIF"). We hold significant fee title rights which generate production for our account from third parties leasing those lands. The Before Royalty volumes presented do not include reserves associated with this Royalty Interest Production. The After Royalty volumes presented include our Royalty Interest Reserves.

For definitions of terms used in our oil and gas disclosure, please refer to the Advisory.

Classifications of reserves as proved or probable are only attempts to define the degree of certainty associated with the estimates. There are numerous uncertainties inherent in estimating quantities of bitumen, oil and natural gas reserves. **It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves.** There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. For additional information on our pricing assumptions, reserves data and other oil and gas information, readers should review "Reserves Data and Other Oil and Gas Information", "Risk Factors – Operational Risks – Uncertainty of Reserves and Future Net Revenue Estimates" and "Risk Factors – Operational Risks – Uncertainty of Contingent and Prospective Resource Estimates", each within our AIF, available on our website at cenovus.com.

SUMMARY OF COMPANY INTEREST OIL AND GAS RESERVES AS AT DECEMBER 31, 2014

(Forecast Prices and Costs)

BEFORE ROYALTIES [1]	BITUMEN *(MMbbls)*	HEAVY OIL *(MMbbls)*	LIGHT & MEDIUM OIL & NGLs *(MMbbls)*	NATURAL GAS & CBM *(Bcf)*
Proved Reserves				
Developed Producing	197	114	94	778
Developed Non-Producing	41	2	4	14
Undeveloped	1,732	40	22	4
Total Proved Reserves	**1,970**	**156**	**120**	**796**
Probable Reserves	1,330	123	46	260
Total Proved plus Probable Reserves	**3,300**	**279**	**166**	**1,056**

AFTER ROYALTIES [2]	BITUMEN *(MMbbls)*	HEAVY OIL *(MMbbls)*	LIGHT & MEDIUM OIL & NGLs *(MMbbls)*	NATURAL GAS & CBM *(Bcf)*
Proved Reserves				
Developed Producing	159	97	84	793
Developed Non-Producing	31	1	3	14
Undeveloped	1,306	36	18	4
Total Proved Reserves	**1,496**	**134**	**105**	**811**
Probable Reserves	1,005	97	40	252
Total Proved plus Probable Reserves	**2,501**	**231**	**145**	**1,063**

(1) Does not include Royalty Interest Reserves.
(2) Includes Royalty Interest Reserves.

ROYALTY INTEREST	BITUMEN (MMbbls)	HEAVY OIL (MMbbls)	LIGHT & MEDIUM OIL & NGLs (MMbbls)	NATURAL GAS & CBM (Bcf)
Proved Reserves				
Developed Producing	–	1	6	40
Developed Non-Producing	–	–	–	–
Undeveloped	–	–	–	–
Total Proved Reserves	**–**	**1**	**6**	**40**
Probable Reserves	–	1	2	12
Total Proved plus Probable Reserves	**–**	**2**	**8**	**52**

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AS AT DECEMBER 31, 2014

(Forecast Prices and Costs)

	DISCOUNTED AT %/YEAR					UNIT VALUE DISCOUNTED AT 10% (1)
BEFORE INCOME TAXES *($ millions)*	0%	5%	10%	15%	20%	$/BOE
Proved Reserves						
Developed Producing	13,715	10,972	9,135	7,845	6,894	19.31
Developed Non-Producing	1,471	1,096	848	678	556	22.33
Undeveloped	58,310	25,769	13,177	7,456	4,504	9.69
Total Proved Reserves	**73,496**	**37,837**	**23,160**	**15,979**	**11,954**	**12.38**
Probable Reserves	58,033	19,036	8,364	4,571	2,854	7.07
Total Proved plus Probable Reserves	**131,529**	**56,873**	**31,524**	**20,550**	**14,808**	**10.32**

(1) Unit values have been calculated using Company Interest After Royalties reserves.

	DISCOUNTED AT %/YEAR				
AFTER INCOME TAXES (1) *($ millions)*	0%	5%	10%	15%	20%
Proved Reserves					
Developed Producing	10,984	8,815	7,347	6,313	5,549
Developed Non-Producing	1,088	822	642	518	428
Undeveloped	44,659	19,422	9,819	5,501	3,290
Total Proved Reserves	**56,731**	**29,059**	**17,808**	**12,332**	**9,267**
Probable Reserves	43,148	14,157	6,185	3,349	2,071
Total Proved plus Probable Reserves	**99,879**	**43,216**	**23,993**	**15,681**	**11,338**

(1) Values are calculated by considering existing tax pools and tax circumstances for Cenovus and its subsidiaries in the consolidated evaluation of Cenovus's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see the Company's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2014.

The estimates of future net revenue do not represent fair market value.

RESERVES RECONCILIATION

The following tables provide a reconciliation of Cenovus's Company Interest Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2014, presented using forecast prices and costs. All reserves are located in Canada.

RESERVES RECONCILIATION BY PRINCIPAL PRODUCT TYPE AND RESERVES CATEGORY

COMPANY INTEREST BEFORE ROYALTIES

(Forecast Prices and Costs)

PROVED	BITUMEN (MMbbls)	HEAVY OIL (MMbbls)	LIGHT & MEDIUM OIL & NGLs (MMbbls)	NATURAL GAS & CBM (Bcf)
As at December 31, 2013	1,846	179	115	865
Extensions and Improved Recovery	108	14	17	23
Discoveries	–	–	–	–
Technical Revisions	63	(13)	1	98
Economic Factors	–	–	–	(12)
Acquisitions	–	–	–	2
Dispositions	–	(10)	(1)	(5)
Production [1]	(47)	(14)	(12)	(175)
As at December 31, 2014	**1,970**	**156**	**120**	**796**

PROBABLE	BITUMEN (MMbbls)	HEAVY OIL (MMbbls)	LIGHT & MEDIUM OIL & NGLs (MMbbls)	NATURAL GAS & CBM (Bcf)
As at December 31, 2013	683	140	50	300
Extensions and Improved Recovery	648	7	–	13
Discoveries	–	–	–	–
Technical Revisions	(1)	(21)	(3)	(47)
Economic Factors	–	–	–	(5)
Acquisitions	–	–	–	–
Dispositions	–	(3)	(1)	(1)
Production [1]	–	–	–	–
As at December 31, 2014	**1,330**	**123**	**46**	**260**

PROVED PLUS PROBABLE	BITUMEN (MMbbls)	HEAVY OIL (MMbbls)	LIGHT & MEDIUM OIL & NGLs (MMbbls)	NATURAL GAS & CBM (Bcf)
As at December 31, 2013	2,529	319	165	1,165
Extensions and Improved Recovery	756	21	17	36
Discoveries	–	–	–	–
Technical Revisions	62	(34)	(2)	51
Economic Factors	–	–	–	(17)
Acquisitions	–	–	–	2
Dispositions	–	(13)	(2)	(6)
Production [1]	(47)	(14)	(12)	(175)
As at December 31, 2014	**3,300**	**279**	**166**	**1,056**

(1) Production used for the reserves reconciliation differs from publicly reported production. In accordance with NI 51-101, Company Interest Before Royalties production used for the reserves reconciliation above includes Cenovus's share of gas volumes provided to FCCL for steam generation, but does not include Royalty Interest Production.

BITUMEN ECONOMIC CONTINGENT AND PROSPECTIVE RESOURCES

COMPANY INTEREST BEFORE ROYALTIES *(Billions of Barrels)*	DECEMBER 31, 2014	DECEMBER 31, 2013
Economic Contingent Resources (1)		
Low Estimate	**6.6**	7.0
Best Estimate	**9.3**	9.8
High Estimate	**12.9**	13.6
Prospective Resources (2)		
Low Estimate	**4.4**	4.5
Best Estimate	**7.5**	7.5
High Estimate	**12.7**	12.6

(1) There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

(2) There is no certainty 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.

EXPLORATION AND DEVELOPMENT ACTIVITY

The following tables summarize Cenovus's gross participation and net interest in wells drilled for the periods indicated:

	OIL SANDS		CONVENTIONAL		TOTAL	
EXPLORATION WELLS DRILLED	GROSS	NET	GROSS	NET	GROSS	NET
2014						
Oil	–	–	1	1	1	1
Gas	–	–	–	–	–	–
Dry & Abandoned	–	–	–	–	–	–
Total Working Interest	–	–	1	1	1	1
Royalty	–	–	10	–	10	–
Total Canada	**–**	**–**	**11**	**1**	**11**	**1**
2013						
Oil	–	–	6	6	6	6
Gas	–	–	–	–	–	–
Dry & Abandoned	–	–	–	–	–	–
Total Working Interest	–	–	6	6	6	6
Royalty	–	–	9	–	9	–
Total Canada	–	–	15	6	15	6
2012						
Oil	–	–	8	7	8	7
Gas	–	–	–	–	–	–
Dry & Abandoned	–	–	–	–	–	–
Total Working Interest	–	–	8	7	8	7
Royalty	–	–	20	–	20	–
Total Canada	–	–	28	7	28	7

	OIL SANDS		CONVENTIONAL		TOTAL	
DEVELOPMENT WELLS DRILLED	GROSS	NET	GROSS	NET	GROSS	NET
2014						
Oil	130	65	129	125	259	190
Gas	–	–	–	–	–	–
Dry & Abandoned	–	–	7	7	7	7
Total Working Interest	130	65	136	132	266	197
Royalty	1	–	126	–	127	–
Total Canada	**131**	**65**	**262**	**132**	**393**	**197**
2013						
Oil	91	46	215	206	306	252
Gas	–	–	–	–	–	–
Dry & Abandoned	–	–	2	2	2	2
Total Working Interest	91	46	217	208	308	254
Royalty	3	–	117	–	120	–
Total Canada	94	46	334	208	428	254
2012						
Oil	61	31	349	345	410	376
Gas	–	–	–	–	–	–
Dry & Abandoned	–	–	1	1	1	1
Total Working Interest	61	31	350	346	411	377
Royalty	57	–	129	–	186	–
Total Canada	118	31	479	346	597	377

During the year ended December 31, 2014, Oil Sands drilled 320 gross stratigraphic test wells (196 net wells) and Conventional drilled 30 gross stratigraphic test wells (30 net wells).

During the year ended December 31, 2014, Oil Sands drilled three gross service wells (two net wells) and Conventional drilled 38 gross service wells (33 net wells). SAGD well pairs are counted as a single producing well in the table above.

For all types of wells except stratigraphic test wells, the calculation of the number of wells is based on the number of surface locations. For stratigraphic test wells, the calculation is based on the number of bottomhole locations.

INTEREST IN MATERIAL PROPERTIES

The following table summarizes Cenovus's landholdings as at December 31, 2014:

	DEVELOPED		UNDEVELOPED (1)		TOTAL (2)	
LANDHOLDINGS *(thousands of acres)*	GROSS	NET	GROSS	NET	GROSS	NET
Alberta						
Oil Sands						
Crown (3)	485	383	1,857	1,398	2,342	1,781
Conventional						
Fee (4)	1,935	1,935	433	433	2,368	2,368
Crown (3)	1,157	1,054	542	476	1,699	1,530
Freehold (5)	68	58	12	10	80	68
Total Alberta	3,645	3,430	2,844	2,317	6,489	5,747
Saskatchewan						
Oil Sands						
Crown (3)	–	–	63	63	63	63
Conventional						
Fee (4)	81	81	424	424	505	505
Crown (3)	42	28	99	88	141	116
Freehold (5)	14	10	6	3	20	13
Total Saskatchewan	137	119	592	578	729	697
Manitoba						
Conventional						
Fee (4)	5	5	252	252	257	257
Total Manitoba	5	5	252	252	257	257
Total	**3,787**	**3,554**	**3,688**	**3,147**	**7,475**	**6,701**

(1) Undeveloped includes land that has not yet been drilled, as well as land with wells that have never produced hydrocarbons or that do not currently allow for the production of hydrocarbons.
(2) Includes approximately 1.1 million gross acres partially leased to third parties and excludes approximately 1.3 million gross acres fully leased to third parties.
(3) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which Cenovus has purchased a working interest lease.
(4) Fee lands are those lands in which Cenovus has a fee simple interest in the mineral rights and have either: (i) not leased out all of the mineral zones; or (ii) retained a working interest. The current fee lands summary includes all freehold titles owned by Cenovus that have one or more zones that remain unleased or available for development.
(5) Freehold lands are those lands owned by individuals (other than a government or Cenovus) in which Cenovus holds a working interest lease.

ADVISORY

FINANCIAL INFORMATION

Basis of Presentation Financial information in our Annual Report is in Canadian dollars, except where another currency has been indicated, and has been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis.

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

FORWARD-LOOKING INFORMATION

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "plan", "forecast" or "F", "future", "target", "project", "capacity", "could", "should", "focus", "goal", "outlook", "potential", "may", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules; projected future value or net asset value; our portfolio of development opportunities; projections for 2015 and future years; forecast operating and financial results; planned capital expenditures, including the timing and financing thereof; the financial flexibility of our 2015 budget, including the ability thereof to respond to near-term volatility; expected future production, including the timing, stability or growth thereof; expected future refining capacity; expected reserves and contingent and prospective resources; broadening market access; improving cost structures; dividend plans and strategy, including with respect to the dividend reinvestment plan,; anticipated timelines for future regulatory, partner or internal approvals; future impact of regulatory measures; forecasted commodity prices; future use and development of technology, including to reduce our environmental impact; future credit ratings; and projected shareholder value and return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

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

2015 guidance is based on an average diluted number of shares outstanding of approximately 760 million. It assumes: Brent US$53.50/bbl, WTI of US$50.50/bbl; Western Canadian Select of US$36.25/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.70/GJ; Chicago 3-2-1 crack spread of US$11.75/bbl; and an exchange rate of $0.83 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; 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 heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation, including sufficient crude-by-rail or other alternate transportation; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see "Risk Factors" in our Annual Information Form for the year ended December 31, 2014 (see Additional Information).

OIL AND GAS INFORMATION

Terminology The estimates of reserves and resources data and related information were prepared effective December 31, 2014 by independent qualified reserves evaluators ("IQREs"), in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. ("McDaniel") January 1, 2015 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, 2014 (see Additional Information). The following definitions are applicable to our oil and gas disclosure in our Annual Report:

After Royalties means volumes after deduction of royalties and includes Royalty Interest Reserves.

Before Royalties means volumes before deduction of royalties and excludes Royalty Interest Reserves. We hold significant fee title rights which generate production for our account from third parties leasing those lands. The Before Royalties volumes presented in the reserves reconciliation (i) do not include reserves associated with this production and (ii) differs from other publicly reported production as it includes Cenovus gas volumes provided to the FCCL Partnership for steam generation, but does not include royalty interest production.

Company Interest means, in relation to production, reserves, resources and property, the interest (operating or non-operating) held by us.

Gross means: (a) in relation to wells, the total number of wells in which we have an interest; and (b) in relation to properties, the total area of properties in which we have an interest.

Net means: (a) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and (b) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

RESERVES TERMINOLOGY:

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on analysis of drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates:

Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Each of the reserves categories may be divided into developed and undeveloped categories:

Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided as follows:

Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Royalty Interest Reserves means those reserves related to our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any reserves related to other royalty interests, such as overriding royalties, to which we are entitled.

Royalty Interest Production means the production related to our royalty entitlement on lands to which we hold fee title and which have been leased to third parties, plus any production related to other royalty interests, such as overriding royalties, to which we are entitled.

RESOURCES TERMINOLOGY:

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 2014 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.

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 (see Additional Information).

Barrels of Oil Equivalent Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one 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.

Finding and Development Costs Finding and development costs disclosed in our Annual Report and used for calculating our recycle ratio do not include the change in estimated future development costs. Cenovus uses finding and development costs without changes in estimated future development costs as an indicator of relative performance to be consistent with the methodology accepted within the oil and gas industry.

Finding and development costs for *proved reserves*, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $31.65/BOE for the year ended December 31, 2014, $32.97/BOE for the year ended December 31, 2013 and averaged $29.27/BOE for the three years ended December 31, 2014. Finding and development costs for *proved plus probable reserves*, excluding the effects of acquisitions and dispositions but including the change in estimated future development costs were $19.38/BOE for the year ended December 31, 2014, $40.85/BOE for the year ended December 31, 2013 and averaged $22.98/BOE for the three years ended December 31, 2014. These finding and development costs were calculated by dividing the sum of exploration costs, development costs and changes in future development costs in the particular period by the reserves additions (the sum of extensions and improved recovery, discoveries, technical revisions and economic factors) in that period. The aggregate of the exploration and development costs incurred in a particular period and the change during that period in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that period.

For additional information about our finding and development costs, capital investment and reserves additions, see our February 12, 2015 news release available on our website at cenovus.com.

ABBREVIATIONS

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

™ denotes a trademark of Cenovus Energy Inc.

OIL AND NATURAL GAS LIQUIDS

bbl	barrel
bbls/d	barrels per day
Mbbls/d	thousand barrels per day
MMbbls	million barrels
NGLs	natural gas liquids
BOE	barrel of oil equivalent
BOE/d	barrel of oil equivalent per day
WTI	West Texas Intermediate
WCS	Western Canadian Select

NATURAL GAS

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	Gigajoule
CBM	Coal Bed Methane

ADDITIONAL INFORMATION

For convenience, references in this document to the "Company", "Cenovus", "we", "us", "our" and "its" may, where applicable, refer only to Cenovus Energy Inc. or include any relevant direct and indirect subsidiary corporations and partnerships ("subsidiaries") of Cenovus Energy Inc., and the assets, activities and initiatives of such subsidiaries.

Additional information relating to Cenovus, including our Annual Information Form/Form 40-F for the year ended December 31, 2014, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

INFORMATION *for* SHAREHOLDERS

ANNUAL MEETING

Shareholders are invited to attend the annual and special meeting to be held on Wednesday, April 29, 2015 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

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 www.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 www.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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LEADERSHIP *at* CENOVUS

Our Executive Team guides our plans, prioritizes our initiatives and leads by example. Our experienced Board members guide our decisions and actions. Underpinning their strong leadership is a tremendous depth of talent and knowledge that will enable us to execute on our business plan and continue to increase value for shareholders. We welcomed Robert Pease to our Executive Team in 2014. Robert is leading our market access initiatives.

EXECUTIVE OFFICERS

From left to right: Kerry D. Dyte, *Executive Vice-President, General Counsel & Corporate Secretary*, Robert W. Pease, *Executive Vice-President, Markets, Products & Transportation*, Brian C. Ferguson, *President & Chief Executive Officer*, Sheila M. McIntosh, *Executive Vice-President, Environment & Corporate Affairs*, Hayward J. Walls, *Executive Vice-President, Strategy & Organization Development*, Harbir S. Chhina, *Executive Vice-President, Oil Sands*, Ivor M. Ruste, *Executive Vice-President & Chief Financial Officer*, John K. Brannan, *Executive Vice-President & Chief Operating Officer*.

BOARD OF DIRECTORS

From left to right: Colin Taylor, *Toronto, Ontario,* (1,2,3) Valerie A.A. Nielsen, *Calgary, Alberta,* (1,3,4) Charles M. Rampacek, *Dallas, Texas,* (3,4,5) Michael A. Grandin, *Board Chair, Calgary, Alberta,* (3,7) Ian W. Delaney, *Toronto, Ontario,* (2,3,5) Ralph S. Cunningham, *Houston, Texas,* (2,3,5) Brian C. Ferguson, *Calgary, Alberta,* (6) Patrick D. Daniel, *Calgary, Alberta,* (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

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.

CENOVUS.COM

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