Energy. It's as essential to our lives as food and water.

Everybody, everywhere, deserves access to energy.

Yet, nearly 40% of the people in the world today live without modern energy sources. And that number is growing because the population of developing countries is increasing.

demand from developing countries + world population = 56% more energy needed over the next 30 years

And, we're going to need every kind of energy there is.

To heat our homes. To cook our food. To light our communities.

	NUCLEAR	RENEWABLES	NATURAL GAS	COAL	OIL
2010	5%	11%	22%	28%	34%
2040	7%	15%	23%	27%	28%

(Types of energy used worldwide – current and projected percentages)

But, for transportation, the heavy lifter is oil.

Today oil provides 92% of the world's transportation fuel, and is forecast to provide 85% of it by 2040.

92% Oil

4% Natural gas
2% Biofuels
1% Electricity
1% Other
(Based on 2010 global demand for transportation fuels)

International Energy Agency
Data taken from: World Energy Outlook 2012 © OECD/IEA, 2012 table, 11.4 p. 346.

cenovus ENERGY

2013 ANNUAL REPORT

FUELLING WORLD PROGRESS

What is Canada's role?

With the third largest oil reserves on the planet, Canada has enough oil to take us to the next century and beyond.

Since 97% of Canada's oil reserves are in the oil sands, oil sands development is key to Canada's continued prosperity and to helping meet world demand for oil. What's important is that the industry continues to make environmental advances through innovation and technology.

More than **2 trillion dollars**

The amount new oil sands development is expected to contribute to the Canadian economy between 2010 and 2035.

In 2010, about 260,000 people worked directly or indirectly in the oil sands industry.

By 2035, that number is estimated to be more than 1 million.

We need to get the oil to where it's needed.

Being able to transport this valuable resource across the country and around the world benefits everyone. Right now, Canada produces about three million barrels of oil per day, and that number continues to grow. It's essential that we have a variety of options – like pipelines, rail and tankers – to get that oil to the people who need it and want it.

From what you see and hear in the media and on the internet, you might think that Canadians are against oil and oil sands development. Actually, years of research show that most Canadians are supportive of the oil sands. But, for whatever reason, they're not speaking up about their support.

75%

Percentage of Canadians who are neutral to positive about oil sands development.

(Abacus Data, December 2013)

At Cenovus, we're speaking up.

We're proud of what we do and of the responsible way in which we do it. Oil has played a critical role in raising the quality of life for those who have had access to it. As the world's primary transportation fuel for more than a century, oil has enabled the global economy.

FIND OUT MORE

MORE2STORY

To find out more about the role that oil plays in the energy mix, visit More2theStory.com.

This site was created by Cenovus to engage Canadians in a conversation about oil and to provide them with information about this valuable resource.

The data presented on these pages have been compiled from a number of sources. Please visit **More2theStory.com** for a complete listing of those sources and additional resources.

"We believe in applying fresh, progressive thinking to be the best in our industry. That means being innovative and responsibly delivering energy resources the world needs."

BRIAN FERGUSON / President & Chief Executive Officer

Our Foster Creek oil sands drilling project.

We take our commitment to responsible energy development very seriously.

Our strategy

Our strategy is as simple as it is effective: 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 (NAV) and paying a strong and sustainable dividend.

OUR INTEGRATED APPROACH

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 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
- Refining to help reduce the impact of commodity price fluctuations

Our 10-year business plan lays out how we will achieve our strategy. It is reviewed regularly to ensure we are able to anticipate and create change when needed, so we are able to be resilient and deliver reliable, predictable results.

Our progress

It's important to us that you know our annual operational milestones and can track our progress as we build our business over many years.

Our progress is measured by our ability to deliver on the commitments and milestones we set each year and, longer term, by our ability to:

- Meet our 2023 target of producing about 525,000 barrels of oil per day net to Cenovus (which means it doesn't include the amount allocated to our partner*)
- Continually grow our NAV over the long term, with an interim target of achieving a NAV of $56 per share by the end of 2015
- Maintain a solid balance sheet and pay a strong and sustainable dividend

*Our Foster Creek, Christina Lake and Narrows Lake oil sands assets are 50 percent owned by ConocoPhillips and operated by Cenovus.

OUR 2013 MILESTONES

- Grow reserves and contingent resources
- Drill 350 to 400 gross stratigraphic test wells and assess results
- Submit regulatory application for Foster Creek phase J expansion
- Submit regulatory application for Christina Lake phase H expansion
- Provide updates on Grand Rapids and Telephone Lake pilot projects
- Achieve first production at Christina Lake phase E
- Increase rail takeaway capacity for oil to approximately 10,000 bbls/d
- Progress preliminary work and initiate facility construction at Narrows Lake phase A
- Anticipate regulatory approval for Grand Rapids in the fourth quarter (now expected in early 2014)
- Evaluate debottlenecking opportunities at the Wood River Refinery
- Continue to evaluate light oil opportunities
- Leverage supply chain management to improve operating costs (ongoing)

OUR 2014 MILESTONES

- Grow reserves and contingent resources
- Drill approximately 300 stratigraphic test wells and assess results
- Anticipate Grand Rapids regulatory approval
- Progress Narrows Lake phase A engineering, procurement and construction
- Seek partnership approval for Wood River Refinery debottleneck project
- Reach effective production capacity at Christina Lake phase E
- Anticipate Telephone Lake regulatory approval
- Achieve first production at Foster Creek phase F
- Increase rail takeaway capacity for oil to approximately 30,000 bbls/d

DELIVERING ENERGY RESPONSIBLY

Our Cenovus

Our purpose, our promise and our 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.

Our five areas of focus provide a framework for the work we do at Cenovus.

EXECUTIONAL EXCELLENCE

Providing a safe workplace and delivering on our commitments

VALUE CREATION

Achieving a material increase in shareholder value

INNOVATION

Balancing the strength of our manufacturing approach with our need to innovate and continuously improve

REPUTATION & COMMUNICATION

Living up to our commitments; telling our story

HEALTHY ORGANIZATION

Ensuring Cenovus is a great place to work

Improving performance through innovation

We aim to maximize value for our shareholders. Through innovation we seek to improve both our economic and environmental performance.

We've made great strides over the years and are always looking for ways to get better.

That's why we're a founding member of Canada's Oil Sands Innovation Alliance (COSIA). Formed in 2012, COSIA is all about collaboration – oil sands producers finding solutions to improve environmental performance by focusing on areas such as water, land and greenhouse gases.

It's also why we have a technology development team that is currently working on numerous projects, many of which could have further environmental benefits.

Our award-winning SkyStrat™ drilling rig is a great example of how technology has enabled us to reduce our environmental footprint. This scaled-down version of a stratigraphic test well drilling rig can be flown to remote locations by helicopter. By reducing the need to build access roads, we expect the rig will decrease our environmental footprint and operating costs in those areas.

Our environmental commitments

These five statements help guide our employees in making smart environmental choices every day.

- Taking care of the environment is part of what we do
- We incorporate environmental considerations when planning our work
- Through innovation and efficiency, we limit our impacts on air, land and water resources
- Our activities are temporary, we conserve resources and reclaim impacts
- We take actions to continually improve our environmental performance

Supporting the needs of communities

It's important to us that we have strong, mutually beneficial relationships founded on trust and respect with the communities near our operating areas.

We want those communities to be better off as a result of us being there. For example, we have signed long-term agreements with many Aboriginal communities near our operations.

We also do a significant amount of business with Aboriginal-owned companies and joint ventures in those communities. Since Cenovus was formed in 2009, we have spent more than $1 billion on goods and services supplied by Aboriginal businesses, including $395 million in 2013 alone – reflecting our ongoing efforts to contract locally whenever possible in the areas where we operate.

CONTENTS

For additional information about the forward-looking statements, non-GAAP measures and reserves and resources estimates contained in this Annual Report, see the Advisory.

Message from our President & Chief Executive Officer

I am proud of what we do at Cenovus. As a Canadian oil company, we produce a product that drives the global economy. That raises the standard of living around the world. That improves quality of life and helps fuel world progress.

That may sound bold, but it's the transportation of people, goods and services that enables a global economy and allows us to advance as a society. It's why so many countries are focused on getting access to oil.

We do our utmost to live up to the responsibility that goes with being a developer of one of Canada's most valuable resources. We are proud of the way we're developing the oil sands and stand behind our actions and our promise to unlock challenging resources in a way that makes Canadians proud. You can count on Cenovus's commitment to develop our resources safely and responsibly, and to always strive to be better at how we do it.

As you saw at the front of this report, Canada has lots of oil. What our country doesn't have is sufficient pipeline capacity to get that oil to the countries that both want it and need it.

As our industry and Cenovus continue to grow production, getting our oil to customers in a safe manner is a top priority. As a company, we know we can't sit back and wait for those challenges to work themselves out. That's not our culture and that's not good business. We are seeking new markets for our product, supporting new pipeline projects, expanding our rail capacity, challenging the status quo about oil transportation and reminding people about the benefits of oil.

Those activities are a big part of what we did in 2013, a year characterized by successes, challenges and opportunities. A year in which we fortified our capacity for long-term growth and business success.

SUCCESSES, CHALLENGES, OPPORTUNITIES

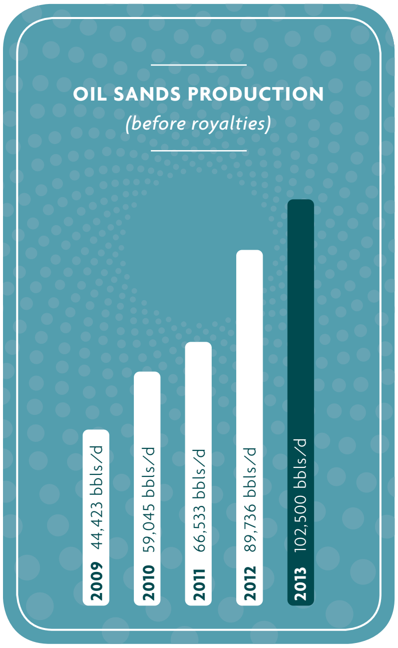
I believe having a strong, well-defined culture is not just critical for the long-term success of a company, it's a competitive advantage. We have been building the Cenovus culture since our inception in late 2009, and have made real strides this past year. We successfully embedded the essence of our purpose, promise and values (which were rolled out to all our employees in November 2012) into how we do our work, and strengthened our sense of who we are as a company.

> It is my continued belief that a company's long-term success is dependent on three things: having smart, dedicated people, having a strong culture and having a high-quality asset base. At Cenovus, we have all three.

A great demonstration of the kind of company we are occurred during the floods in southern Alberta this past June. The floods caused major damage and affected the lives of thousands of people. Despite the magnitude of this natural disaster, our employees came together to successfully activate our business continuity plan and ensure all critical systems, communications and business functions continued with minimal disruption. During that time of need, many of them also joined in the extensive volunteer effort, and Cenovus donated $1 million to more than 20 not-for-profit organizations to assist with disaster relief efforts.

We also had a number of successes in our oil sands operations in 2013:

- We reached a major milestone at Christina Lake in July when we achieved first oil production at phase E, our tenth expansion phase. We received regulatory approval to optimize phases C, D and E, and work continues for phases F and G, with first production scheduled for 2016 and 2017, respectively.



- We successfully completed major maintenance turnarounds at both Foster Creek and Christina Lake.
- We are on track with construction of Foster Creek phases F, G and H.
- We are moving ahead with construction of the first phase of Narrows Lake, our third oil sands project, and expect to see first oil production in 2017.
- We completed a dewatering pilot at Telephone Lake, which successfully tested the removal of an underground layer of non-potable water sitting on top of the oil sands deposit. This is an excellent example of our ability to meet technological challenges, enhance project economics and reduce our impact on the environment. We anticipate regulatory approval for Telephone Lake in mid-2014.
- We also progressed the regulatory application for our Grand Rapids project towards approval.
- We had tremendous success using a SkyStrat™ drilling rig during our summer drilling program in 2013. This heli-portable drilling rig is a Cenovus innovation that allows us to fly a drilling rig into a remote location one piece at a time. Since everything is flown in, no roads are needed. That means limited disturbance of the forest and no additional traffic. Work is under way on a second SkyStrat™ drilling rig.

That momentum is exciting to see. It means we are creating value and strengthening our ability to deliver – on our commitments, on your expectations of us, and ultimately on our growth strategy.

On the conventional side, we continued to focus on light and medium oil development utilizing horizontal wells in southern Alberta. And we commenced an enhanced oil recovery pilot at our Suffield operations that is anticipated to increase oil recovery. We kept production on track, and continued to generate strong cash flow which is always good news for our financial strength.

That's not to say that the year didn't have its challenges.

An area that continues to be of concern to me, the Executive Team and the Board is our workplace safety performance. The health and safety of our workforce is very important at Cenovus. But it's not just about saying it. It's about living it every day.

Our Christina Lake oil sands drilling project is expected to have gross production capacity of more than 300,000 barrels of oil per day.

Our increased focus on workplace safety in 2013 saw our total recordable injury frequency decrease by 12 percent from 2012. However, with more people working at our project sites there continues to be an increase in incidents. We will be putting even more effort into turning that around in 2014 through programs like Start Safe, which stresses the importance of safety throughout the organization, including with our contractors.

We pride ourselves on being one of the lowest cost producers in the industry. However, our trend line on overall operating costs is going in the wrong direction. We are committed to reversing that trend through better collaboration and greater focus on expenditures. We also need to increase our efforts to capture synergies from our centralized shared services structure.

Operationally, we had some technical challenges this past year. What's important is that we not only addressed them, we learned from them.

At Pelican Lake we had steady, incremental heavy oil production volumes. However, some challenges with our infill drilling program resulted in slower than expected production growth. As such, we've scaled back our drilling program in some areas and placed greater focus on those areas that have yielded better results.

We are pleased to have received external validation for our performance.

2013 recognition:

- ★ Named to the Dow Jones Sustainability World Index (the only Canadian oil and gas company)
- ★ Named to the Dow Jones Sustainability Index, North America
- ★ Included on the Canada 200 Climate Disclosure Leadership Index
- ★ Named to the Corporate Knights Global 100 list, which recognizes the world's most sustainable corporations
- ★ Received a Canadian Association of Petroleum Producers Environmental Performance Award
- ★ Received recognition for best sustainability practice by *Investor Relations* Magazine Canada Awards

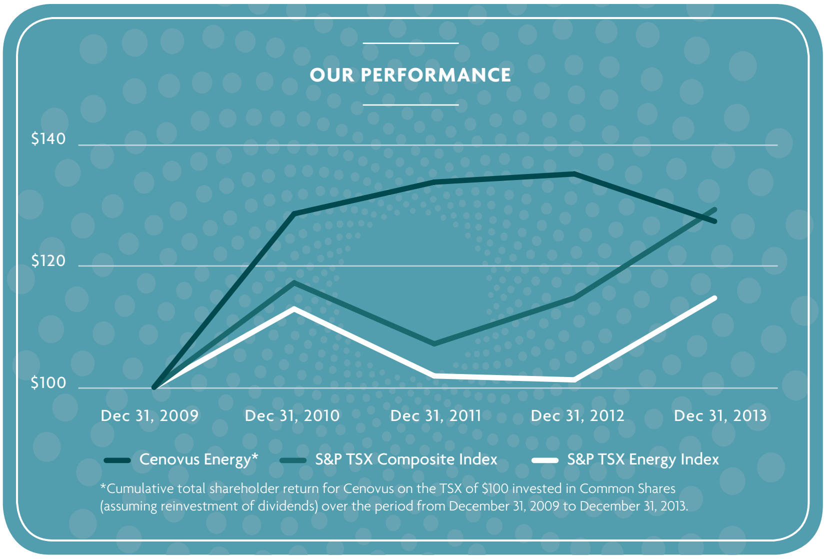
At Foster Creek, some challenges with routine well maintenance and reservoir management processes, resulted in a temporary decrease in production volumes. This reduction likely played a role in our share price performance (see chart at right).

It was a reminder that we need to anticipate the changes that will occur at our projects as part of the natural evolution of steam-assisted gravity drainage (SAGD) development, so we can adapt our operating procedures accordingly. We have already made some changes at Foster Creek.

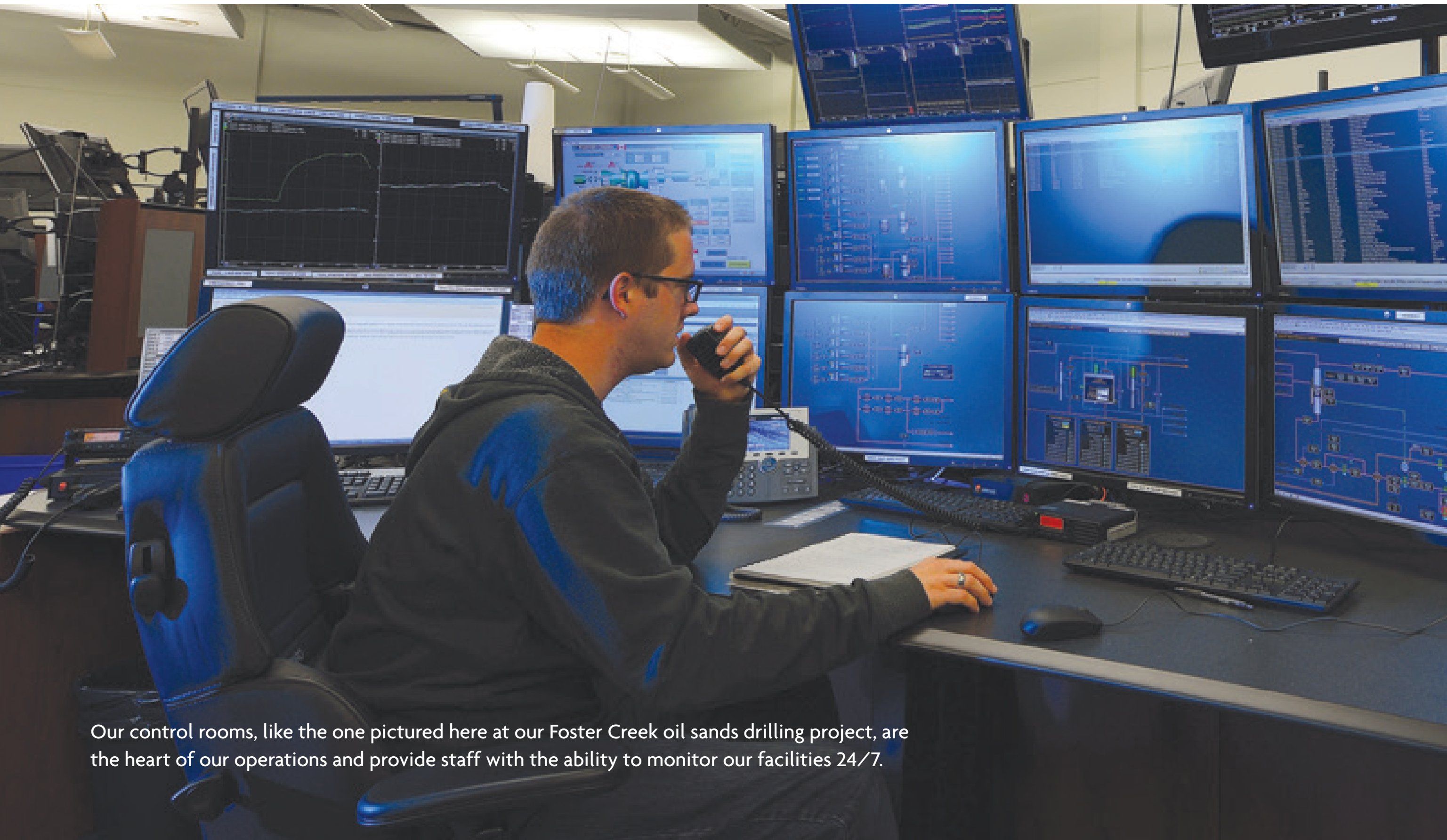
We have built more preventive well maintenance into our plans going forward, and are modifying our operating procedures now that the individual steam chambers in the initial areas of the project have started to evolve into common chambers.

One strength of our phased approach to our oil sands projects is that we are able to transfer the knowledge and lessons learned from one phase to the next and to other projects. It's about improving efficiencies, increasing reliability and maintaining operating cost discipline as we grow.

At Cenovus, execution excellence has been a focus since our inception in 2009. It has become part of our DNA, and is a big part of what motivates us to learn, improve, and innovate. Our leaders are empowered to turn challenges into opportunities, so we end up stronger. That's the approach we have taken with market access.



*Cumulative total shareholder return for Cenovus on the TSX of $100 invested in Common Shares (assuming reinvestment of dividends) over the period from December 31, 2009 to December 31, 2013.



Our control rooms, like the one pictured here at our Foster Creek oil sands drilling project, are the heart of our operations and provide staff with the ability to monitor our facilities 24/7.

I firmly believe that the transportation challenges that are currently limiting Canada's access to markets should be viewed as one of the greatest opportunities available to Cenovus and the entire oil industry. By identifying new ways to get our product to market, we have the opportunity to broaden our customer base, diversify our transportation options to offshore markets and receive better pricing for our products. We continue to focus on expanding our markets for our product both in North America and around the world. We have secured space for our oil on proposed pipeline projects to the U.S. Gulf Coast and Canadian West Coast, and on the proposed Energy East pipeline to eastern Canada.

As part of our portfolio approach to transportation, we also increased our rail shipping capacity to approximately 10,000 barrels of oil per day in 2013. Rail provides flexibility that complements our pipeline strategy and we expect it will play an instrumental role in our long-term plans. We are able to make these kinds of transportation commitments because we expect decades of predictable, reliable oil sands growth ahead of us.

In a year that saw volatile and complex market conditions, we once again demonstrated the value of our integrated approach. Having a strategy that includes both producing and refining assets helps manage the risks associated with fluctuating commodity prices. That gives us greater financial stability and positions us for long-term growth and business success.

Our Wood River and Borger refineries performed well in 2013, generating operating cash flow in excess of capital invested of approximately $1 billion, net to Cenovus. In addition, our refineries processed a combined total of 222,000 barrels per day of heavy oil, up 12 percent from 2012 – the largest volume of heavy oil since Cenovus became a joint owner of the facilities in 2007. Our ability to process higher volumes of less expensive heavy oil also resulted in an improved feedstock cost advantage.

More than 1,500 staff attended our 2013 Innovation Summit, sharing ideas and learning from each other.

In 2014, we will continue to focus on predictable, reliable performance, and on total shareholder return.

HIGHLIGHTS OF OUR PERFORMANCE IN 2013

- We generated cash flow of $3.6 billion.
- Our strong cash flow, combined with our disciplined capital management, allowed us to fund growth plans while growing our dividend by 10 percent to $0.968 per share – part of our commitment to our shareholders.
- We grew average oil sands production to 102,500 barrels of oil per day, up 14 percent over 2012.
- We increased our proved bitumen reserves by eight percent and our economic bitumen best estimate contingent resources by two percent in 2013 compared with 2012.

WHAT'S AHEAD FOR 2014: A RENEWED FOCUS ON RESULTS

The strong foundation we have built since 2009 has served us well. In a short time, we have cultivated a work environment that fosters the right people with the right attitude and the right skills. As we continue to grow, developing our people and enhancing our technical and leadership competencies will be critical to executing with excellence and ensuring Cenovus continues to be a great place to work.

As we enter our fifth year of operation, I am extremely optimistic about Cenovus and our future.

What you can expect from us in 2014 is a renewed focus on delivering predictable, reliable performance.

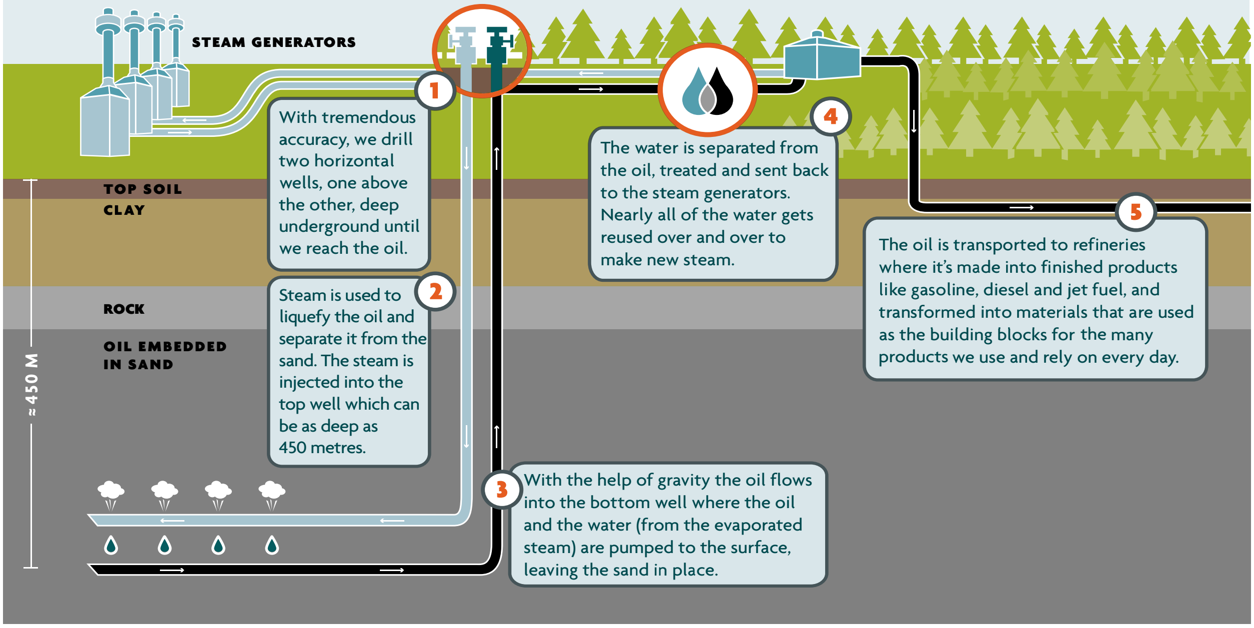
We will continue to leverage what we learned in 2013 and will be disciplined with our capital allocation. We plan to invest between $2.8 and $3.1 billion in 2014 – primarily in oil projects, where we see the best opportunity for production growth in the near term. With a robust inventory of approved oil projects now in place, we believe it's time to allocate more of our capital spending to developing those projects that create the greatest value possible for you, our shareholders.

We will be focused on changing behaviours at our work sites, reinforcing the attitude that safety is everyone's responsibility.

We will continue to advance our ability to get our oil to those markets that will have the best return for our company. We will continue to focus on getting our overall costs back in line. We will continue to strengthen our culture – building our leadership and technical skills, and ensuring a greater degree of consistency and efficiency across the company. And, as always, we will remain focused on total shareholder return – growing net asset value (NAV) and paying a strong and growing dividend over time. In fact, our Board of Directors recently approved a dividend increase of 10 percent for the first quarter of 2014.

STEAM-ASSISTED GRAVITY DRAINAGE

In the oil sands, 80 percent of the oil is deep underground and requires a specialized technology to drill and pump it to the surface. The technology we use to recover the oil in our oil sands projects is called steam-assisted gravity drainage or SAGD. Cenovus is a leader in SAGD. We've made a number of enhancements to the technology over the years and continue to look for ways to improve the technology so we can produce more oil and further reduce the impact we have on the environment. Here's how it works.



This well pad at our Foster Creek oil sands drilling project uses Wedge Well™ technology that allows us to increase total recovery of oil while decreasing our environmental impact.

FUELLING OUR BUSINESS

It is my continued belief that a company's long-term success is dependent on three things: having smart, dedicated people, having a strong culture and having a high-quality asset base. At Cenovus, we have all three. Our business helps fuel world progress but it is our people who fuel our business.

Over the past four years, we have made it a priority to develop a culture that fosters collaboration, innovation and trust. And we have strived to create a workplace where employees enjoy coming to work every day knowing their contributions are valued. We have achieved that by concentrating on our five areas of focus: executing with excellence, creating value, innovating, building our reputation, and providing a healthy workplace.

The men and women of Cenovus are the bright minds who can turn any challenge into opportunity; who make this company an exciting place to be. I want to thank them for the passion they have for their work and for the energy they have for this company.

I would also like to thank our Board of Directors for their continued advice and guidance and for challenging us to never be satisfied with our performance – to expect more from ourselves, so we continuously improve and grow our company responsibly. We fully accept that challenge.

We learned a lot this past year about being inspired by challenges and how they can strengthen our capacity for long-term growth and business success. We are only just getting started. We have so many exciting opportunities ahead of us.

BRIAN C. FERGUSON
President & Chief Executive Officer

Message from our Board Chair

This year's report theme, the value of oil, captures the lead role Cenovus has taken in championing oil – the value it brings to our lives, the need for it worldwide, and the responsible way the company develops its resources.

From a governance perspective, this theme also provides an excellent way for everyone – including employees, management, the Board, stakeholders and interested observers – to assess Cenovus's accomplishments.

Viewing our results and actions through such a lens calls for one to integrate both objective measures of how well the company is doing with equally important subjective measures of the way Cenovus conducts its business to produce a complete picture.

In its most commonly used sense, the value of oil encompasses all elements of real economic value. From the company's perspective, it includes results from its research, development, production, transportation, refining, marketing and sales activities, all of which ultimately translate into cash flow and net asset value – which Cenovus has adopted as an important performance measure.

For our shareholders, it includes important investment results such as returns, dividend growth, financial capacity, resilience and share price. For society at large, it includes the intrinsic value of the many industrial and consumer materials and products derived from oil that range from gasoline for your car and jet fuel for airplanes to plastics used in everyday items such as product packaging and smart phones.

But that's only part of the picture. Thinking about the value of oil in the broadest sense also calls for consideration of subjective measures of the ethical value of Cenovus's actions as it goes about its business.

For example, one might take into account what the company is doing to ensure a safe workplace, how it's going about minimizing its impact on the environment, how it works with the communities its operations affect, and the opportunities it provides employees for personal and professional development. In other words, such subjective measures establish a means of assessing specific additional outcomes produced by employing the principles and standards of behaviour that form Cenovus's culture.

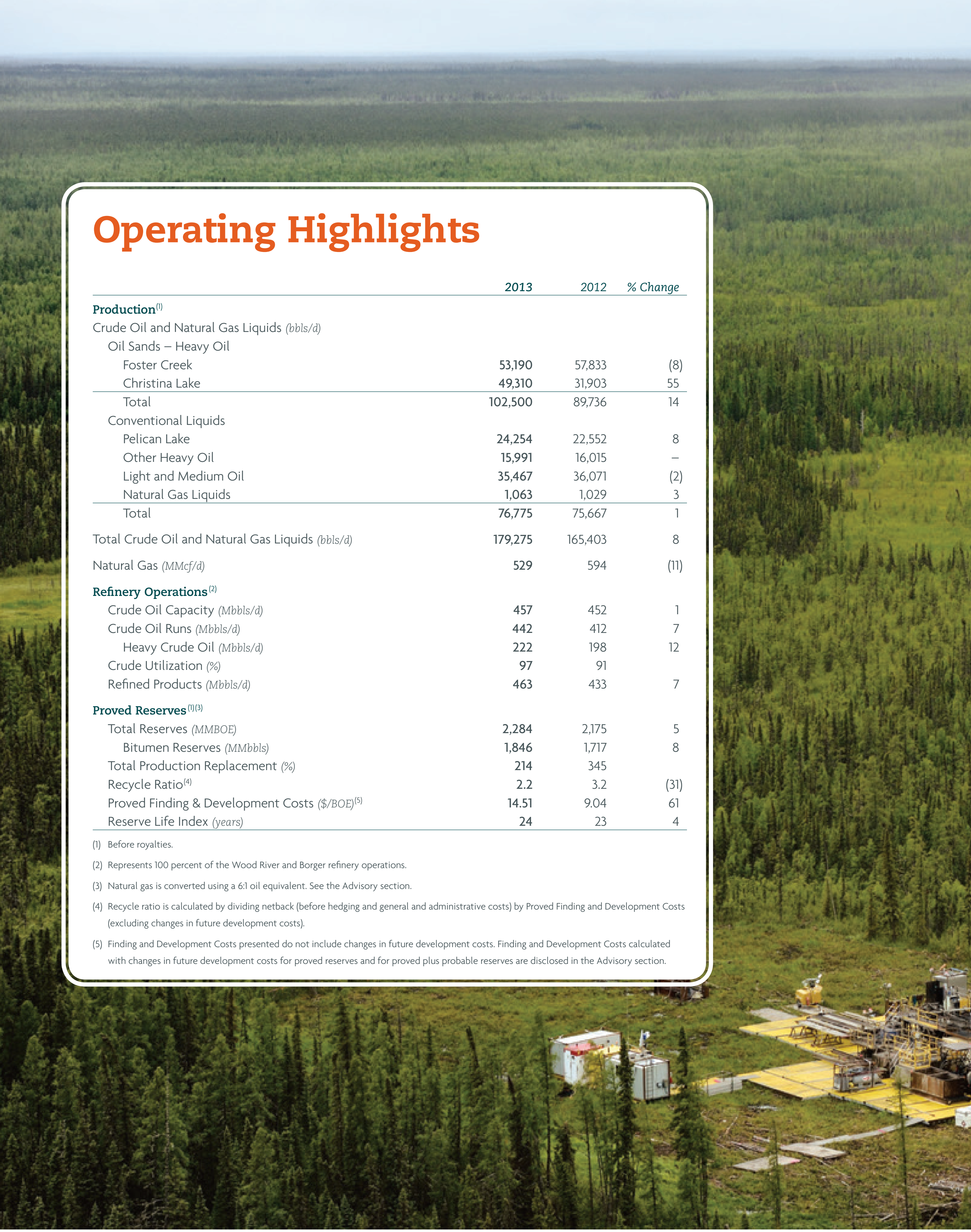
Your Board believes that, taken together, elements embodied in the above streams of thought provide a useful and complete set of performance measures for internal use by employees, management and directors, as well as a comprehensive framework for our stakeholders and other interested parties to use in fully assessing our results.

We encourage you to read and watch Cenovus's public statements and posted videos about the company's plans, intentions and accomplishments, and to follow its results. By doing so, you will be better able to make your own judgment about how Cenovus is creating shareholder and societal value by conducting its business responsibly and ethically. And doing so will perhaps help you form your own view of both the intrinsic value of oil and the value of Cenovus oil.

Respectfully submitted on behalf of the Board.

MICHAEL A. GRANDIN / Board Chair

In the face of volatile prices, our integrated strategy reduces risk and helps us to have a more reliable cash flow to invest in our business. Pictured here is our Wood River Refinery.



Operating Highlights

	2013	2012	% Change
Production[(1)]			
Crude Oil and Natural Gas Liquids *(bbls/d)*			
Oil Sands – Heavy Oil			
Foster Creek	**53,190**	57,833	(8)
Christina Lake	**49,310**	31,903	55
Total	**102,500**	89,736	14
Conventional Liquids			
Pelican Lake	**24,254**	22,552	8
Other Heavy Oil	**15,991**	16,015	–
Light and Medium Oil	**35,467**	36,071	(2)
Natural Gas Liquids	**1,063**	1,029	3
Total	**76,775**	75,667	1
Total Crude Oil and Natural Gas Liquids *(bbls/d)*	**179,275**	165,403	8
Natural Gas *(MMcf/d)*	**529**	594	(11)
Refinery Operations[(2)]			
Crude Oil Capacity *(Mbbls/d)*	**457**	452	1
Crude Oil Runs *(Mbbls/d)*	**442**	412	7
Heavy Crude Oil *(Mbbls/d)*	**222**	198	12
Crude Utilization *(%)*	**97**	91	
Refined Products *(Mbbls/d)*	**463**	433	7
Proved Reserves[(1)(3)]			
Total Reserves *(MMBOE)*	**2,284**	2,175	5
Bitumen Reserves *(MMbbls)*	**1,846**	1,717	8
Total Production Replacement *(%)*	**214**	345	
Recycle Ratio[(4)]	**2.2**	3.2	(31)
Proved Finding & Development Costs *($/BOE)*[(5)]	**14.51**	9.04	61
Reserve Life Index *(years)*	**24**	23	4

(1) Before royalties.

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

(3) Natural gas is converted using a 6:1 oil equivalent. See the Advisory section.

(4) Recycle ratio is calculated by dividing netback (before hedging and general and administrative costs) by Proved Finding and Development Costs (excluding changes in future development costs).

(5) Finding and Development Costs presented do not include changes in future development costs. Finding and Development Costs calculated with changes in future development costs for proved reserves and for proved plus probable reserves are disclosed in the Advisory section.

Financial Highlights

($ Millions, except per share and other amounts as noted)	**2013**	2012	*% Change*
Net Revenues	**18,657**	16,842	11
Operating Cash Flow (1)	**4,468**	4,451	–
Cash Flow (1)	**3,609**	3,643	(1)
Per Share – Diluted	**4.76**	4.80	
Operating Earnings (1)	**1,171**	868	35
Per Share – Diluted	**1.55**	1.14	
Net Earnings	**662**	995	(33)
Per Share – Diluted	**0.87**	1.31	
Capital Investment	**3,262**	3,368	(3)
Net Acquisition and Divestiture Activity	**(251)**	38	
Net Capital Investment	**3,011**	3,406	(12)
Dividends Per Common Share *($/share)*	**0.968**	0.880	10
Dividend Yield *(%)* (2)	**3.2**	2.6	
Debt to Capitalization *(%)* (1)	**33**	32	
Debt to Adjusted EBITDA *(times)* (1)	**1.2**	1.1	

(1) Non-GAAP measures as referenced in the Advisory section.

(2) Based on TSX closing share price at year end.

Our SkyStrat™ drilling rig is a great example of innovation and continuous improvement at work.

Management's Discussion and Analysis

For the Year Ended December 31, 2013

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated February 12, 2014, should be read in conjunction with our December 31, 2013 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 12, 2014, 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, while the Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended its approval by the Board, which occurred on February 12, 2014. Additional information about Cenovus, including our quarterly and annual reports and 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 have been prepared 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, 2013, we had a market capitalization of approximately $23 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 2013 average crude oil and NGLs (collectively, "crude oil") production was in excess of 179,000 barrels per day and our average natural gas production was 529 MMcf per day. Our refinery operations processed an average of 442,000 gross barrels per day of crude oil feedstock into an average of 463,000 gross barrels per day of refined product.

OUR STRATEGY

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on continually building our net asset value and paying a strong and sustainable dividend.

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

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

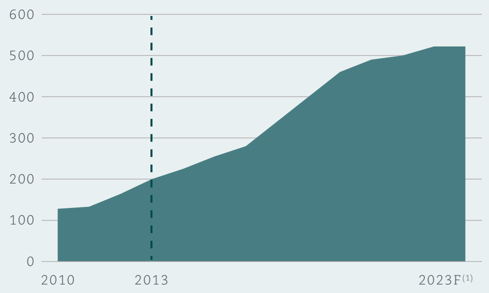
To achieve our expected production targets noted below, we anticipate our total annual capital investment to average between $3.0 and $3.7 billion for the next decade. This capital investment is expected to be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations as well as prudent use of our balance sheet capacity. We continue to focus on executing our 10-year business plan in a predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Production

We plan to increase our net oil sands bitumen production to approximately 435,000 barrels per day and our net crude oil production, including our conventional oil operations, to approximately 525,000 barrels per day by the end of 2023. We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek, Christina Lake, Narrows Lake, Telephone Lake, Pelican Lake and our conventional tight oil opportunities. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base by drilling approximately 300–450 gross stratigraphic test wells each year for the next five years.

TOTAL CRUDE OIL PRODUCTION, NET TO CENOVUS

(Mbbls/d)



(1) Expected net production.

OIL SANDS

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

	2013 Ownership Interest (percent)	*2013 Net Production Volumes* (bbls/d)	*2013 Gross Production Volumes* (bbls/d)	*Current Expected Gross Production Capacity* (bbls/d)
Existing Projects				
Foster Creek	**50**	**53,190**	**106,380**	**310,000**
Christina Lake	**50**	**49,310**	**98,620**	**310,000**
Narrows Lake	**50**	**–**	**–**	**130,000**
Emerging Projects				
Telephone Lake	**100**	**–**	**–**	**300,000**
Grand Rapids	**100**	**–**	**–**	**180,000**

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

Foster Creek is producing from phases A through E. Expansion work is underway at phases F, G and H with added production capacity from phase F expected in the third quarter of 2014 and phases G and H in 2015 and 2016, respectively. In the first quarter of 2013, we submitted a joint application and environmental impact assessment ("EIA") for Foster Creek phase J, a 50,000 barrel per day phase. We anticipate receiving regulatory approval in the first quarter of 2015.

Christina Lake is producing from phases A through E. Our phase E expansion commenced steam injection in June 2013 and first production was achieved in July 2013. Expansion work is currently underway for phase F, including cogeneration, and phase G, with added production capacity expected in 2016 and 2017, respectively. In the first quarter of 2013, we submitted an EIA for Christina Lake phase H, a 50,000 barrel per day phase. We anticipate receiving regulatory approval in the fourth quarter of 2014.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, and final partner approval for phase A, a 45,000 barrel per day phase, in December 2012. Construction of the phase A plant commenced in August 2013 and we anticipate first production in 2017.

Two of our emerging projects are Telephone Lake and Grand Rapids. At our Telephone Lake project located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012 and we completed the pilot in October 2013. We successfully displaced water with compressed air, displacing approximately 70 percent of below-ground top water. In December 2011, we submitted a revised joint application and EIA due to an increase in the Telephone Lake project development area. We anticipate receiving regulatory approval in the second quarter of 2014. At our Grand Rapids project located within the Greater Pelican region, a SAGD pilot project is underway. We anticipate receiving regulatory approval in the first quarter of 2014 for a 180,000 barrel per day commercial SAGD operation.

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 upstream and refining operations and provides cash flows to help fund our growth opportunities.

	2013	
($ millions)	*Crude Oil* [1]	*Natural Gas*
Operating Cash Flow [2]	**1,388**	**415**
Capital Investment	**1,169**	**22**
Operating Cash Flow net of Related Capital Investment	**219**	**393**

(1) Includes NGLs.

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

We have established conventional crude oil and natural gas producing assets and developing tight oil assets in Alberta. We also inject carbon dioxide to enhance oil recovery at our Weyburn operations in Saskatchewan. Located in the Athabasca region of northeastern Alberta is our wholly owned Pelican Lake property. This property produces conventional heavy oil using polymer flood technology.

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.

	2013 Ownership Interest (percent)	*2013 Gross Nameplate Capacity (Mbbls/d)*
Wood River [1]	**50**	**311**
Borger	**50**	**146**

(1) Effective January 1, 2014, Wood River has a nameplate capacity of 314,000 barrels per day.

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

($ millions)	2013
Operating Cash Flow [1]	1,143
Capital Investment	107
Operating Cash Flow net of Related Capital Investment	**1,036**

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

Technology and Environment

Both technology development, including research activities, and the environment are playing increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technology with the goals of increasing recoveries from our reservoirs, while reducing the amount of water, natural gas and electricity consumed in our operations, and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches, potentially reducing costs. We have a track record of developing innovative solutions that unlock challenging crude oil resources and builds on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return. We paid dividends of $0.968 per share in 2013, a 10 percent increase from 2012 (2012 – $0.88 per share; 2011 – $0.80 per share).

Net Asset Value

We measure our success in a number of ways with a key measure being growth in net asset value. In 2013, our net asset value was positively impacted by our overall operational and financial performance offset by the impact of changing commodity prices. We continue to believe that our goal of doubling December 2009 net asset value by the end of 2015 is achievable.

2013 OPERATING AND FINANCIAL HIGHLIGHTS

2013 continued to reflect the strength of our integrated approach. Overall, the integration of our business and growing crude oil production helped to reduce the impact of commodity price fluctuations. We completed our planned capital programs, submitted regulatory applications for expansions at Foster Creek and Christina Lake and increased our rail shipping capacity.

OPERATIONAL RESULTS

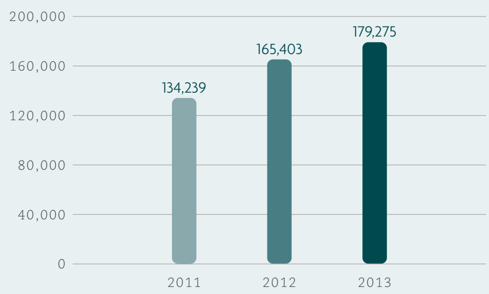
Total crude oil production averaged 179,275 barrels per day, an increase of eight percent from 2012.

Crude oil production from our Oil Sands segment averaged 102,500 barrels per day, an increase of 14 percent, primarily driven by increased production at Christina Lake. Average production at Christina Lake was 49,310 barrels per day, a 55 percent increase, as phase D reached full capacity and phase E, our tenth expansion phase at Cenovus, started to produce in July 2013. Phase E increases nameplate capacity to 138,000 gross barrels per day. The phase E ramp-up is proceeding similar to the ramp-up of phases C and D, which reached nameplate capacity within six to nine months of first production.

Foster Creek production averaged 53,190 barrels per day, a decrease of eight percent, resulting from a number of production matters that are discussed in the Reportable Segments section under Oil Sands.

TOTAL CRUDE OIL PRODUCTION VOLUMES

(bbls/d)



Our Conventional crude oil production averaged 76,775 barrels per day, an increase of one percent, due to strong horizontal well performance from our current drilling program in southern Alberta and higher Pelican Lake production, offset by decreased production due to the sale of our Lower Shaunavon asset in July 2013, and expected natural declines. Pelican Lake production averaged 24,254 barrels per day, an increase of eight percent resulting from additional infill wells coming on-stream throughout 2012 and 2013, as well as an increased response from the polymer flood program.

Our proved bitumen reserves increased eight percent to over 1.8 billion barrels and our economic bitumen best estimate contingent resources increased two percent to 9.8 billion barrels, highlighting our strong resource base. Additional information about our resources is included in the Oil and Gas Reserves and Resources section of this MD&A.

Our refining operations processed an average of 442,000 (2012 – 412,000) gross barrels per day of crude oil, of which 222,000 gross barrels per day was heavy crude oil (2012 – 198,000). We produced 463,000 gross barrels per day of refined products, an increase of about 30,000 gross barrels per day or seven percent, as refined product output last year was impacted by planned turnarounds at both refineries.

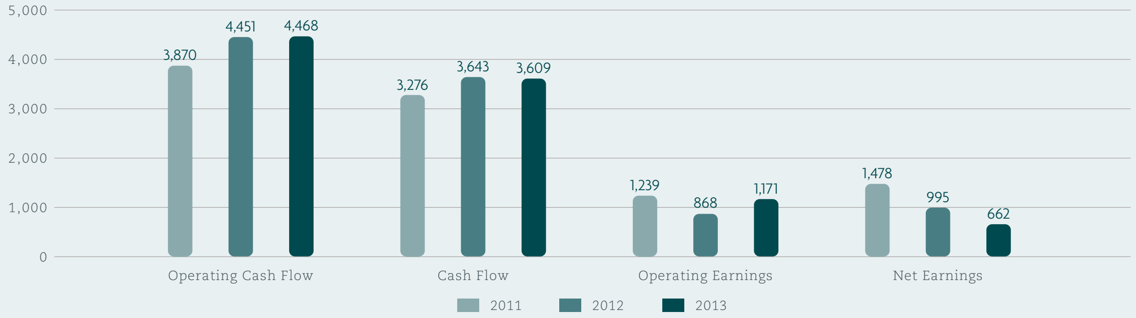
Other significant operational results in 2013 compared with 2012 include:

- Receiving regulatory approval for an optimization program for Christina Lake phases C, D and E which is expected to add up to 22,000 barrels per day of gross capacity in 2015;
- Completing our first major planned turnaround at Christina Lake;
- The closing of the Lower Shaunavon asset divestiture for proceeds of approximately $240 million;
- Managing our natural gas production, which declined 11 percent to an average of 529 MMcf per day due to expected natural declines; and
- Increasing our access to new sales markets by increasing our rail shipping capacity to 10,000 barrels per day by the end of 2013.

FINANCIAL RESULTS

OPERATING CASH FLOW (1), CASH FLOW, OPERATING EARNINGS AND NET EARNINGS

($ millions)



(1) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.

Our integrated approach has resulted in consistent and predictable financial results. Operating Cash Flow and Cash Flow remained relatively flat in 2013 as compared to 2012.

Financial highlights for 2013 compared with 2012 include:

Revenues

Revenues of $18,657 million, increasing $1,815 million or 11 percent as a result of:

- Refining and Marketing revenues rising $1,350 million primarily due to higher refinery output, partially offset by declines in refined product prices. Revenues from third-party sales of crude oil were higher as a result of a rise in purchased crude oil volumes and higher crude oil and condensate pricing;
- Crude oil sales volumes increasing eight percent;
- Our average crude oil and natural gas sales prices (excluding financial hedging) rising two percent to $67.01 per barrel and 32 percent to $3.20 per Mcf, respectively; and
- A rise in condensate volumes and prices used in blending.

These increases to revenues were partially offset by declines in natural gas production volumes.

Operating Cash Flow

In 2013, Operating Cash Flow was $4,468 million, an increase of $17 million. Upstream Operating Cash Flow increased $147 million, or five percent, to $3,325 million due to higher crude oil production volumes at Christina Lake and rising crude oil and natural gas sales prices, partially offset by lower realized risk management gains, increasing operating costs and declines in natural gas production volumes. Crude oil sales prices increased two percent primarily due to the rise in West Texas Intermediate ("WTI"), which averaged US$98.05 per barrel (2012 – US$94.15 per barrel) and the weakening of the Canadian dollar, despite the average decline in Western Canadian Select ("WCS") of US$0.27 per barrel.

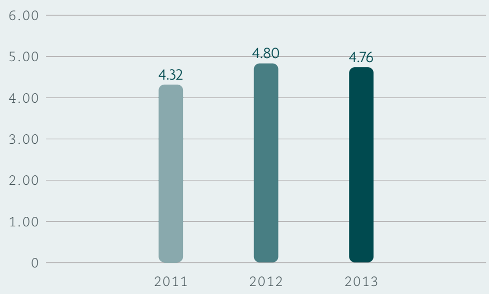
These increases were partially offset by Operating Cash Flow from our Refining and Marketing segment decreasing $130 million to $1,143 million primarily due to lower market crack spreads and higher costs associated with Renewable Identification Numbers ("RINs"), partially offset by an improved feedstock cost advantage attributed to processing a higher proportion of heavy crude oil at a discounted price and an increase in refined product output. The Chicago and Midwest Combined 3-2-1 (“Group 3”) market crack spreads decreased by approximately US$6 per barrel and US$8 per barrel, respectively. 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.

Cash Flow

Cash Flow decreased one percent to $3,609 million, remaining relatively flat as a result of consistent Operating Cash Flow in 2013 as compared to 2012, reflecting the strength of our integrated approach. Declines in Cash Flow were primarily due to higher pre-exploration expense, finance costs, excluding the unwinding of the discount on decommissioning liabilities, and general and administrative expenses, excluding non-cash long-term incentive costs. Decreases in cash tax compared to 2012 partially offset the decline in Cash Flow.

CASH FLOW PER SHARE – DILUTED

($/share)



Operating Earnings

In addition to changes in Cash Flow discussed above, Operating Earnings increased $303 million, or 35 percent, to $1,171 million due to no goodwill impairment in 2013 compared to a goodwill impairment of $393 million recorded in 2012 and a decrease in deferred tax expense of $111 million, not including tax on unrealized risk management (gains) losses and non-operating unrealized foreign exchange (gains) losses. Higher Operating Earnings were partially offset by increased depreciation, depletion and amortization (“DD&A”) as a result of higher production and higher DD&A rates.

Net Earnings

In addition to changes in Operating Earnings discussed above, Net Earnings decreased $333 million or 33 percent, to $662 million, primarily due to:

- After-tax unrealized risk management losses of $310 million compared with gains of $43 million in 2012;
- Realized foreign exchange losses of $146 million, after-tax, as a result of a decision made by our partner to pay the remaining principal on the Partnership Contribution Receivable (described further in the Financial Results section of this MD&A); and
- After-tax non-operating unrealized foreign exchange losses of $52 million compared with gains of $84 million in 2012.

Capital Investment

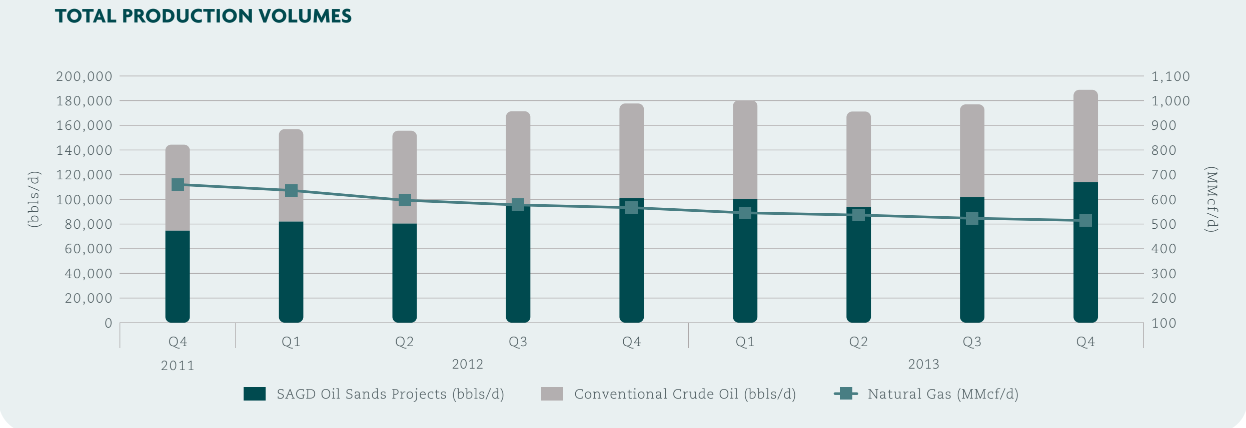
Capital investment was $3,262 million, decreasing three percent, primarily due to reduced capital investment in our Conventional segment, as a result of discontinued spending related to our Lower Shaunavon asset and declines in spending at Pelican Lake, and lower spending on corporate assets. Within our Oil Sands operations, there was a decrease in capital investment at Telephone Lake, as spending decreased with completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. In 2013, spending related to the operation of the dewatering pilot, which was completed in the fourth quarter of 2013.

Declines in capital investment were partially offset by increases at Christina Lake and Foster Creek, with continued focus on the development of our expansion phases, and at Narrows Lake, with construction commencing on phase A in 2013.

Dividend

We paid dividends of $0.968 per share (2012 – $0.88 per share), an increase of 10 percent over 2012. This demonstrates our commitment to pay a strong and sustainable dividend as part of delivering total shareholder return.

OPERATING RESULTS



In 2013, the operating and reportable segments changed from those presented in prior periods to match Cenovus's new operating structure. Our Pelican Lake property is now being managed within our Conventional segment. All prior period results have been restated.

CRUDE OIL PRODUCTION VOLUMES

(barrels per day)	**2013**	***Percent Change***	2012	*Percent Change*	2011
Oil Sands					
Foster Creek	**53,190**	**(8%)**	57,833	5%	54,868
Christina Lake	**49,310**	**55%**	31,903	173%	11,665
	102,500	**14%**	89,736	35%	66,533
Conventional					
Pelican Lake	**24,254**	**8%**	22,552	10%	20,424
Other Heavy Oil	**15,991**	**–%**	16,015	2%	15,657
Light & Medium Oil	**35,467**	**(2%)**	36,071	18%	30,524
NGLs [1]	**1,063**	**3%**	1,029	(7%)	1,101
	76,775	**1%**	75,667	12%	67,706
Total Crude Oil Production	**179,275**	**8%**	165,403	23%	134,239

(1) NGLs include condensate volumes.

In 2013, our crude oil production increased eight percent driven by higher production at Christina Lake as a result of phase D reaching full capacity in the first quarter of 2013 and phase E achieving first production in July 2013.

Foster Creek production decreased eight percent from 2012. In the fourth quarter of 2012, with production levels exceeding the nameplate capacity of our plant, we made a decision to defer some routine workover activity until 2013. That deferral of maintenance resulted in a backlog in the number of wells requiring workovers causing an unanticipated negative impact on our 2013 production volumes. See the Reportable Segments section of this MD&A for more detail.

Our crude oil production from the Conventional segment increased slightly due to better horizontal well performance from our current drilling program in southern Alberta and higher production from Pelican Lake partially offset by the divestiture of our Lower Shaunavon asset and expected natural declines. Pelican Lake production was higher in 2013 with additional infill wells coming on-stream throughout 2012 and 2013 and an increased response from our polymer flood program. In 2013, Lower Shaunavon, which was sold in early July, produced an annual average of 2,095 barrels per day (2012 – 4,411 barrels per day).

NATURAL GAS PRODUCTION VOLUMES

(MMcf per day)	**2013**	2012	2011
Conventional	**508**	564	622
Oil Sands	**21**	30	34
	529	594	656

Spending on natural gas activities continues to be managed in response to the low natural gas price environment. We continue to focus on high rate of return projects and direct capital investment to our crude oil properties.

OPERATING NETBACKS

	Crude Oil (1) *($/bbl)*			**Natural Gas** *($/Mcf)*		
	2013	2012	2011	**2013**	2012	2011
Price (2)	**67.01**	65.79	72.84	**3.20**	2.42	3.65
Royalties	**5.01**	6.29	9.84	**0.04**	0.03	0.06
Transportation and Blending (2)	**3.12**	2.65	2.76	**0.11**	0.10	0.15
Operating Expenses	**15.65**	13.90	13.47	**1.16**	1.10	1.10
Production and Mineral Taxes	**0.48**	0.56	0.56	**0.02**	0.01	0.04
Netback Excluding Realized Risk Management	**42.75**	42.39	46.21	**1.87**	1.18	2.30
Realized Risk Management Gain (Loss)	**1.09**	1.39	(2.79)	**0.32**	1.14	0.87
Netback Including Realized Risk Management	**43.84**	43.78	43.42	**2.19**	2.32	3.17

(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 $28.33 per barrel (2012 – $26.72 per barrel; 2011 – $24.91 per barrel).

In 2013, our average crude oil netback, excluding realized risk management gains and losses, increased $0.36 per barrel from 2012, remaining relatively flat, primarily due to higher sales prices and lower royalties, partially offset by increased operating and transportation and blending costs. The rise in sales price is consistent with the increase in the average WTI price for 2013 and the weakening of the Canadian dollar.

Our average natural gas netback, excluding realized risk management gains and losses, increased $0.69 per Mcf predominantly due to higher sales prices, partially offset by higher per-unit operating costs as a result of the decline in production volumes.

REFINING (1)

	2013	***Percent Change***	2012	*Percent Change*	2011
Crude Oil Runs *(Mbbls/d)*	**442**	**7%**	412	3%	401
Heavy Crude Oil	**222**	**12%**	198	57%	126
Refined Product *(Mbbls/d)*	**463**	**7%**	433	3%	419
Crude Utilization *(percent)*	**97**	**6%**	91	2%	89

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

In 2012, both of our refineries underwent planned turnarounds resulting in an increase to crude oil runs, refined product output and crude utilization in 2013. In addition, the heavy crude oil processed increased 12 percent, reflecting our ability to process a greater proportion of heavy crude oil feedstock and the optimization of our total crude input slate.

Further information on the changes in our production volumes, items included in our operating netbacks and refining statistics can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management section of this MD&A and in the notes to the 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 2013	2013	2012	2011
Crude Oil Prices *(US$/bbl)*				
Brent				
Average	**109.35**	**108.70**	111.68	110.91
End of Period	**110.80**	**110.80**	111.11	107.38
WTI				
Average	**97.61**	**98.05**	94.15	95.11
End of Period	**98.42**	**98.42**	91.82	98.83
Average Differential Brent-WTI	**11.74**	**10.65**	17.53	15.80
WCS				
Average	**65.41**	**72.85**	73.12	77.96
End of Period	**74.80**	**74.80**	59.16	84.37
Average Differential WTI-WCS	**32.20**	**25.20**	21.03	17.15
Condensate (C5 @ Edmonton) Average	**94.37**	**101.77**	100.88	105.34
Average Differential WTI-Condensate (Premium)/Discount	**3.24**	**(3.72)**	(6.73)	(10.23)
Refining Margin 3-2-1 Average Crack Spreads *(US$/bbl)*				
Chicago	**12.29**	**21.77**	27.76	24.55
Group 3	**10.66**	**20.80**	28.56	25.26
Natural Gas Average Prices				
AECO *(C$/Mcf)*	**3.15**	**3.17**	2.41	3.67
NYMEX *(US$/Mcf)*	**3.60**	**3.65**	2.79	4.04
Basis Differential NYMEX-AECO *(US$/Mcf)*	**0.59**	**0.58**	0.38	0.31
Foreign Exchange Rates *(US$/C$1)*				
Average	**0.953**	**0.971**	1.001	1.012

(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.

Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of changes in inland refined product prices. In 2013, the average price of Brent crude oil declined by US$2.98 per barrel due to continued strong growth in North American crude oil supply partially offset by an increase in global crude oil demand and ongoing supply disruptions in various countries.

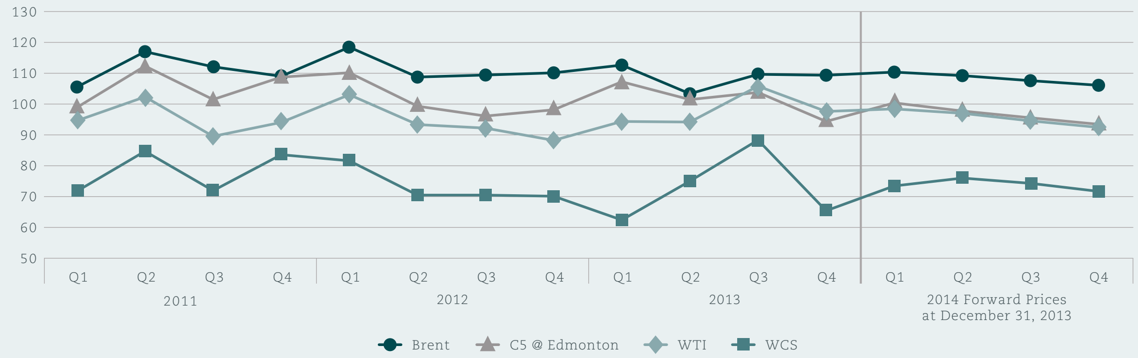
WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average discount between WTI and Brent narrowed in 2013 by US$6.88 per barrel as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved congestion that had developed recently due to the rapid growth in U.S. inland supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential widened by US$4.17 per barrel due to continued growth in Canadian crude oil production and delays in the approval and construction of new pipeline capacity to U.S. markets.

Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from approximately 10 percent to 33 percent. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Condensate prices increased in 2013 by US$0.89 per barrel to US$101.77 per barrel due to increased demand for diluent by oil sands producers. During the fourth quarter of 2013, condensate prices decreased by US$3.77 per barrel from the same period last year due to an increase in condensate transportation capacity and growing condensate supply in the Gulf Coast. In the second half of 2013, condensate traded at a discount to WTI for the first time since the third quarter of 2010 due to the reductions in pipeline congestion causing WTI prices to increase more than condensate prices.

CRUDE OIL BENCHMARKS

(Average US$/bbl)



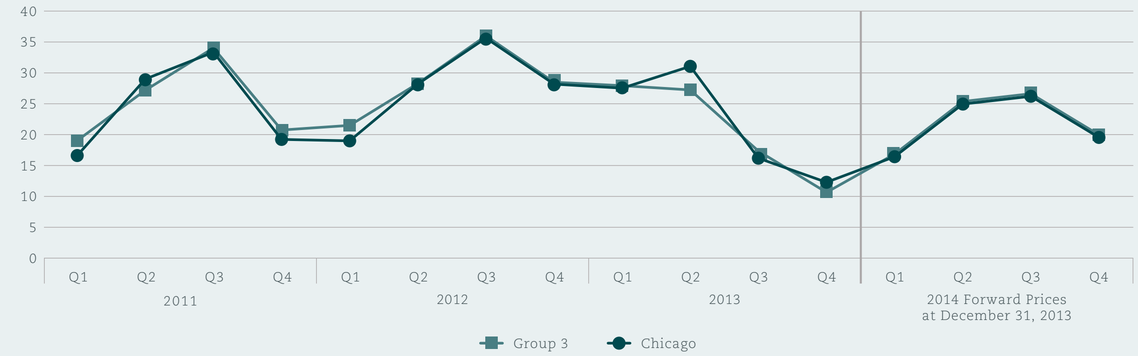
Refining 3-2-1 Crack Spread Benchmarks

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 market crack spreads in the U.S. inland Chicago and Group 3 markets fell in 2013 compared to 2012 primarily due to the strengthening of WTI prices as inland congestion issues were addressed.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and feedstock costs which are based on a first in, first out accounting basis.

REFINING 3-2-1 CRACK SPREAD BENCHMARKS

(Average US$/bbl)



Other Benchmarks

Average natural gas prices increased in 2013 due to a slowing in the pace of supply growth and colder temperatures during the winter heating seasons.

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 2013, the Canadian dollar weakened by $0.03 relative to the U.S. dollar due to interest rates rising faster in the U.S. compared with Canada as the U.S. economy improved, overall weaker commodity prices and concerns regarding the ability of anticipated increases in crude oil supply to access markets. The weakening of the Canadian dollar by three percent in 2013 as compared to 2012 had a positive impact of approximately $560 million on our revenues.

FINANCIAL RESULTS

SELECTED CONSOLIDATED FINANCIAL RESULTS

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

($ millions, except per share amounts)	**2013**	***Percent Change***	*2012*	*Percent Change*	*2011*
Revenues	**18,657**	**11%**	16,842	7%	15,696
Operating Cash Flow (1) (2)	**4,468**	**–%**	4,451	15%	3,870
Cash Flow (1)	**3,609**	**(1%)**	3,643	11%	3,276
Per Share – Diluted	**4.76**	**(1%)**	4.80	11%	4.32
Operating Earnings (1) (3)	**1,171**	**35%**	868	(30%)	1,239
Per Share – Diluted (3)	**1.55**	**36%**	1.14	(30%)	1.64
Net Earnings (3)	**662**	**(33%)**	995	(33%)	1,478
Per Share – Basic (3)	**0.88**	**(33%)**	1.32	(33%)	1.96
Per Share – Diluted (3)	**0.87**	**(34%)**	1.31	(33%)	1.95
Total Assets	**25,224**	**4%**	24,216	9%	22,194
Total Long-Term Financial Liabilities (4)	**6,113**	**–%**	6,128	13%	5,411
Capital Investment (5)	**3,262**	**(3%)**	3,368	24%	2,723
Cash Dividends	**732**	**10%**	665	10%	603
Per Share	**0.968**	**10%**	0.88	10%	0.80

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

(2) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.

(3) We restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more detail.

(4) Includes Long-Term Debt, Partnership Contribution Payable, Risk Management Liability and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.

(5) Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

REVENUES

During 2013, revenues increased $1,815 million or 11 percent compared with 2012.

($ millions)	**2013 *vs.* 2012**	2012 *vs.* 2011
Revenues, Comparative Year	**16,842**	15,696
Increase (Decrease) due to:		
Oil Sands	**610**	739
Conventional	**177**	(100)
Refining and Marketing	**1,350**	731
Corporate and Eliminations	**(322)**	(224)
Revenues, End of Year	**18,657**	16,842

In 2013, upstream revenues rose $787 million, an increase of 14 percent, due to increased blended crude oil sales volumes, rising crude oil, condensate and natural gas sales prices and reduced royalties, partially offset by a decline in natural gas production.

Revenues generated by the Refining and Marketing segment in 2013 increased 12 percent as higher refined product output and a weakening of the Canadian dollar was partially offset by declines in refined product prices. Revenues from third-party sales, undertaken to provide operational flexibility, were higher as a result of a rise in purchased crude oil volumes and higher crude oil and condensate pricing.

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 2012 compared with 2011 as a result of higher blended crude oil sales volumes in our upstream operations and higher refined product output and prices. Increases in revenues were partially offset by declines in the average crude oil and natural gas sales price.

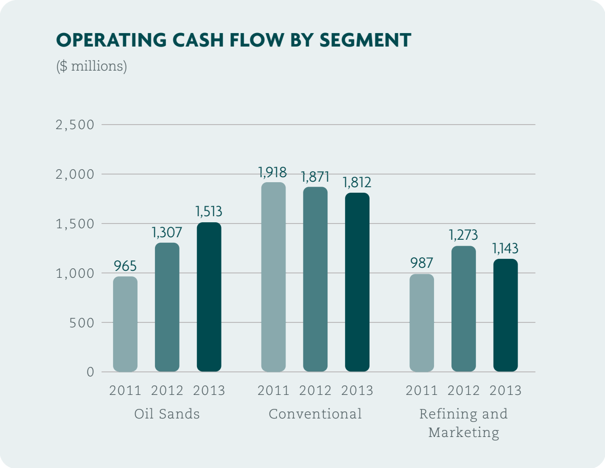
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

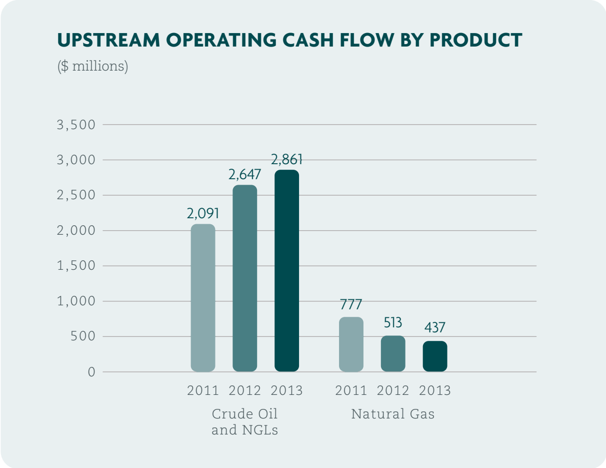
OPERATING CASH FLOW

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.

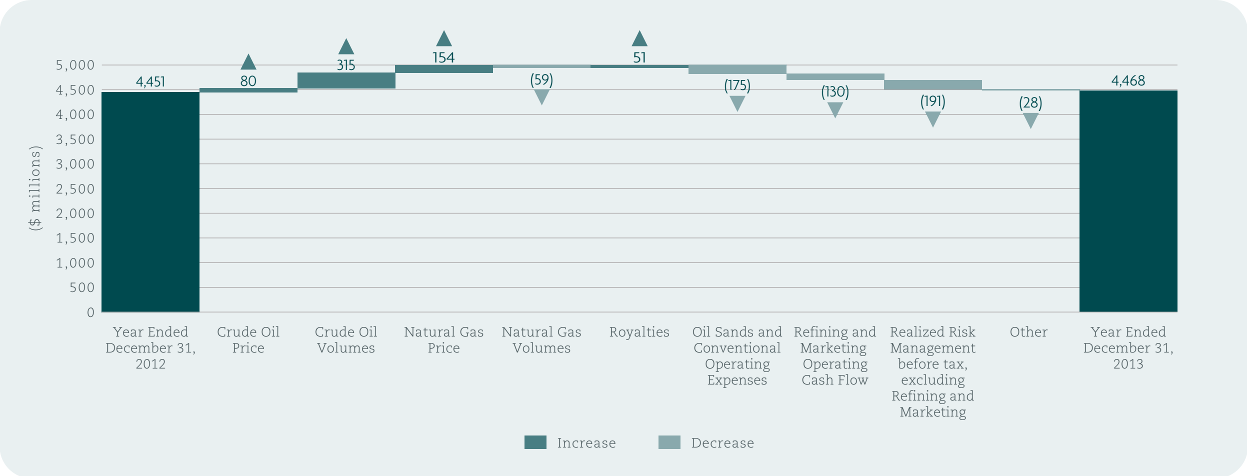
($ millions)	**2013**	2012	2011
Revenues	**19,262**	17,125	15,755
(Add) Deduct:			
Purchased Product	**11,004**	9,506	9,149
Transportation and Blending	**2,074**	1,798	1,369
Operating Expenses [(1)]	**1,803**	1,669	1,399
Production and Mineral Taxes	**35**	37	36
Realized (Gain) Loss on Risk Management Activities	**(122)**	(336)	(68)
Operating Cash Flow	**4,468**	4,451	3,870

(1) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.





Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



Total Operating Cash Flow in 2013 was $4,468 million, relatively unchanged from 2012. As highlighted in the above graph our Operating Cash Flow increased $17 million compared with 2012 primarily due to:

- An increase in our crude oil sales volumes by eight percent; and
- A 32 percent increase in our average natural gas sales price to $3.20 per Mcf and a two percent increase in our average crude oil sales price to $67.01 per barrel.

The increases were partially offset by:

- Realized risk management gains before tax, excluding Refining and Marketing, of $141 million compared with gains of $332 million in 2012;
- An increase in crude oil operating expenses of $184 million, partially due to higher crude oil production. On a per barrel basis, crude oil operating costs increased by $1.75 to $15.65 per barrel; and
- A decline in Operating Cash Flow from Refining and Marketing of $130 million primarily due to the decline in market crack spreads and an increase of $121 million in costs associated with RINs, partially offset by the benefit of processing a higher proportion of heavy crude oil feedstock at a discounted price and an increase in refined product output.

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)	**2013**	2012	2011
Cash From Operating Activities	**3,539**	3,420	3,273
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(120)**	(113)	(82)
Net Change in Non-Cash Working Capital	**50**	(110)	79
Cash Flow	**3,609**	3,643	3,276

Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012

In 2013, Cash Flow decreased $34 million as a result of relatively flat Operating Cash Flow year-over-year, reflecting the strength of our integrated approach. Other changes in Cash Flow included:

- Pre-exploration expense of $64 million;
- An increase in finance costs primarily due to a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014; and
- Higher general and administrative costs, excluding non-cash long-term incentive costs, due to higher rent and staffing costs.

The decreases in our Cash Flow were partially offset by lower current tax of $121 million primarily due to $68 million of withholding tax on a U.S. dividend in 2012, adjustments related to a change in legislation, the finalization of our 2012 tax filings and lower taxable U.S. earnings in the current year.

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 Net Earnings excluding after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt, the effect of changes in statutory income tax rates and the after-tax realized foreign exchange loss on the early receipt of the Partnership Contribution Receivable described below.

On December 17, 2013, our partner exercised its right under the FCCL Partnership Agreement to early retire the remaining principal of the Partnership Contribution Receivable in the amount of US$1.4 billion, net to Cenovus. This resulted in the crystallization of realized foreign exchange losses of $146 million, after-tax, from a weakened Canadian dollar as compared to January 2, 2007, 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)	2013	2012	2011
Net Earnings	**662**	995	1,478
Add (Deduct):			
Unrealized Risk Management (Gain) Loss, after-tax (1) (3)	**310**	(43)	(134)
Non-Operating Unrealized Foreign Exchange (Gain) Loss, after-tax (2) (3)	**52**	(84)	(14)
Realized Foreign Exchange Loss on Early Receipt of the Partnership Contribution Receivable, after-tax (3)	**146**	–	–
(Gain) Loss on Divestiture of Assets, after-tax	**1**	–	(91)
Operating Earnings	**1,171**	868	1,239

(1) The after-tax unrealized risk management (gains) losses include the reversal of unrealized (gains) losses recognized in prior periods.

(2) Includes after-tax unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange (gains) losses on settlement of intercompany transactions and deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt.

(3) The tax benefit of losses are recognized only to the extent that we have capital gains.

In 2013, with consistent Operating Cash Flow, Operating Earnings were $1,171 million, an increase of $303 million, primarily related to there being no goodwill impairment recorded in 2013. In 2012, we recorded a goodwill impairment of $393 million in our Conventional segment.

In addition, Operating Earnings increased due to:

- A decrease in deferred income tax expense of $111 million, not including income tax on unrealized risk management gains and non-operating unrealized foreign exchange losses, as a result of a decrease in income from our refining operations.

Partially offset by:

- Increased DD&A of $248 million as a result of higher production and increased DD&A rates. DD&A also includes an impairment loss of $57 million related to our Lower Shaunavon asset which was recorded in the second quarter of 2013.

NET EARNINGS

($ millions)	2013 vs. 2012	2012 vs. 2011
Net Earnings, Comparative Year	**995**	1,478
Increase (Decrease) due to:		
Operating Cash Flow (1)	**17**	581
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss), after-tax	**(353)**	(91)
Unrealized Foreign Exchange Gain (Loss)	**(110)**	28
Gain (Loss) on Divestiture of Assets	**(1)**	(107)
Expenses (2)	**(217)**	(57)
Depreciation, Depletion and Amortization	**(248)**	(290)
Goodwill Impairment	**393**	(393)
Exploration Expense	**(46)**	(68)
Income Taxes, Excluding Income Taxes on Unrealized Risk Management Gain (Loss)	**232**	(86)
Net Earnings, End of Year	**662**	995

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

(2) Includes general and administrative, research costs, finance costs, interest income, realized foreign exchange (gains) losses, after-tax, other (income) loss, net and Corporate and Eliminations operating expenses.

In addition to the changes discussed above in the Cash Flow and Operating Earnings sections, our Net Earnings decreased 33 percent in 2013 primarily due to after-tax unrealized risk management losses of $310 million compared with gains of $43 million in 2012, a realized foreign exchange loss of $146 million, after-tax, related to the receipt of the remaining principal on the Partnership Contribution Receivable as discussed above, and after-tax non-operating unrealized foreign exchange losses of $52 million compared with gains of $84 million in 2012 as a result of a weaker Canadian dollar in 2013.

Net Earnings decreased during 2012, compared with 2011, primarily due to a goodwill impairment in our Conventional segment and an increase in DD&A. Decreases were partially offset by higher upstream Operating Cash Flow, largely due to increased crude oil production volumes and higher upstream realized risk management gains before tax, and an increase in Operating Cash Flow from Refining and Marketing.

NET CAPITAL INVESTMENT

($ millions)	**2013**	*2012*	*2011*
Oil Sands	**1,883**	1,693	1,098
Conventional	**1,191**	1,366	1,105
Refining and Marketing	**107**	118	393
Corporate and Eliminations	**81**	191	127
Capital Investment	**3,262**	3,368	2,723
Acquisitions	**32**	114	71
Divestitures	**(283)**	(76)	(173)
Net Capital Investment (1)	**3,011**	3,406	2,621

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

Oil Sands capital investment in 2013 focused primarily on the development of the expansion phases at Foster Creek and Christina Lake and development of phase A at Narrows Lake. Capital investment includes the drilling of 339 gross stratigraphic test wells.

Conventional capital investment in 2013 was composed primarily of spending at Pelican Lake on the expansion of the polymer flood and drilling, completion, recompletion programs, and work on facilities at our other Conventional properties. Spending on natural gas activities continues to be managed in response to the low natural gas price environment.

Our capital investment in 2013 in the Refining and Marketing segment focused on capital maintenance and projects improving refinery reliability and safety.

Capital also includes spending on technology development, which plays an integral role in our business. Having an integrated innovation and technology development strategy is vital to our ability to maintain our track record of being a low cost producer, minimize our environmental footprint, and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to enhance the recovery techniques we use to access crude oil and natural gas, and improve our refining processes. In 2013, our capital investment included $129 million on technology development activities. We expensed $24 million related to research activities.

Capital investment in our Corporate and Eliminations segment decreased as costs related to tenant improvements and information technology were lower due to the move into our new office space in the first quarter of 2013.

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

Acquisitions and Divestitures

In 2013, our primary acquisition was for undeveloped land adjacent to our Telephone Lake property.

Divestitures in 2013 included the sale of our Lower Shaunavon asset in July 2013 for proceeds of approximately $240 million plus closing adjustments, undeveloped land in northern Alberta and the cancellation of some of our non-core Oil Sands mineral rights covered under the Lower Athabasca Regional Plan ("LARP") resulting in compensation of $20 million, including interest. The cancelled mineral rights had no direct impact on our business plan, on our current operations at Foster Creek and Christina Lake, or any of our filed applications. Refer to the Risk Management section of this MD&A for more details on the LARP.

CAPITAL INVESTMENT DECISIONS

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

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

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

($ millions)	**2013**	*2012*	*2011*
Cash Flow (1)	**3,609**	3,643	3,276
Capital Investment (Committed and Growth)	**3,262**	3,368	2,723
Free Cash Flow (2)	**347**	275	553
Dividends Paid	**732**	665	603
	(385)	(390)	(50)

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

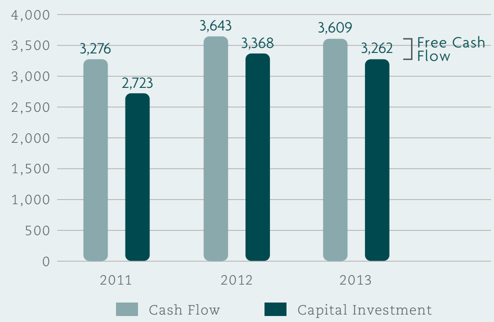
(2) Free Cash Flow is a non-GAAP measure defined as Cash Flow less capital investment.

While cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through financing activities and management of our asset portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

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

FREE CASH FLOW BEFORE DIVIDENDS

($ millions)



REPORTABLE SEGMENTS

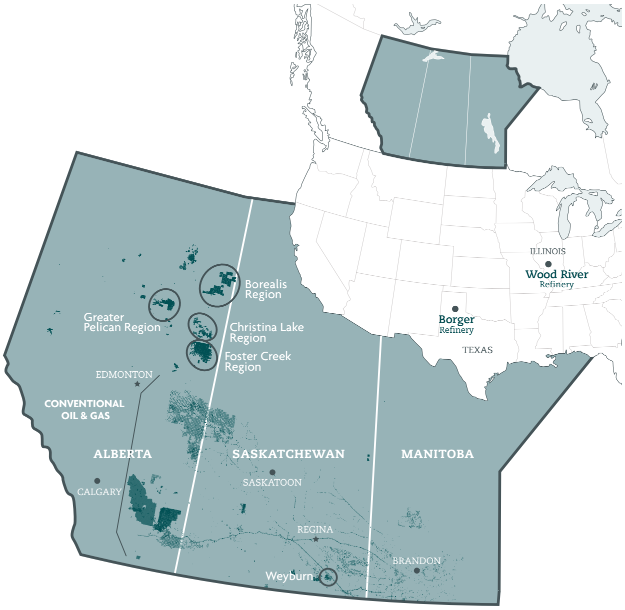
Our reportable segments are as follows:

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

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

Refining and Marketing, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

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



■ Cenovus's major operations

This graphic is for illustrative purposes only. Land at December 31, 2013

The operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's new operating structure. Our Pelican Lake property is now being managed within our Conventional segment. All prior periods have been restated to reflect this presentation. As a result, for the years ended December 31, 2012 and 2011, Operating Cash Flow of $418 million and $305 million, respectively, was reclassified from Oil Sands to Conventional. In addition to the restatement required due to changes in operating segments, research activities previously included in operating expense have been reclassified to conform to the presentation adopted in 2013.

REVENUES BY REPORTABLE SEGMENT

($ millions)	2013	2012	2011
Oil Sands	**3,780**	3,170	2,431
Conventional	**2,776**	2,599	2,699
Refining and Marketing	**12,706**	11,356	10,625
Corporate and Eliminations	**(605)**	(283)	(59)
	18,657	16,842	15,696

OIL SANDS

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

Significant factors that impacted our Oil Sands segment in 2013 compared with 2012 include:

- Christina Lake production increasing 55 percent, to an average of 49,310 barrels per day. Phase D reached full production capacity in 2013 and phase E, our tenth expansion phase at Cenovus, started up in July 2013;
- Completing our first major planned turnaround at Christina Lake resulting in 11 days of full production outage;
- Receiving regulatory approval for an optimization program for Christina Lake phases C, D and E, which is expected to add up to 22,000 barrels per day of gross capacity in 2015;
- Filing joint applications and EIAs for Foster Creek phase J and Christina Lake phase H; and
- Foster Creek production averaging 53,190 barrels per day, a decrease of eight percent, resulting from a number of production matters discussed below.

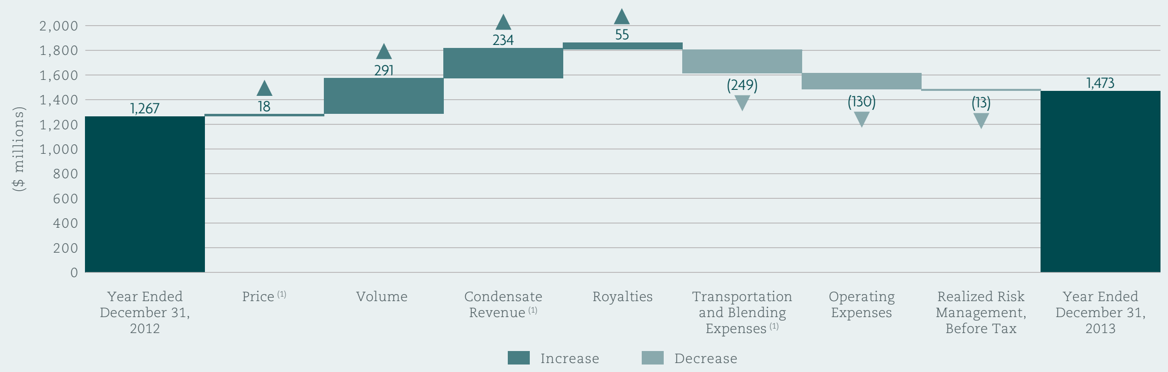
OIL SANDS – CRUDE OIL

Financial Results

($ millions)	2013	2012	2011
Gross Sales	**3,850**	3,307	2,585
Less: Royalties	**131**	186	226
Revenues	**3,719**	3,121	2,359
Expenses			
Transportation and Blending	**1,748**	1,499	1,084
Operating	**531**	401	303
(Gain) Loss on Risk Management	**(33)**	(46)	67
Operating Cash Flow	**1,473**	1,267	905
Capital Investment	**1,878**	1,685	1,084
Operating Cash Flow net of Related Capital Investment	**(405)**	(418)	(179)

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

Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



(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 2013, our average crude oil sales price was $59.10 per barrel, one percent higher than in 2012, primarily due to the weakening of the Canadian dollar, partially offset by a higher proportion of our sales volumes coming from Christina Lake. In 2013, 42,664 barrels per day of Christina Lake production was sold as Christina Dilbit Blend ("CDB") (2012 – 23,220 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

(barrels per day)	**2013**	***Percent Change***	2012	*Percent Change*	2011
Foster Creek	**53,190**	**(8%)**	57,833	5%	54,868
Christina Lake	**49,310**	**55%**	31,903	173%	11,665
	102,500	**14%**	89,736	35%	66,533

In 2013, Foster Creek production averaged 53,190 barrels per day, an eight percent decrease from 2012. In the fourth quarter of 2012, with production levels exceeding the nameplate capacity of our plant, we made a decision to defer some routine well maintenance until 2013. That deferral of maintenance resulted in a backlog in the number of wells requiring workovers causing an unanticipated negative impact on our 2013 production volumes. In 2013, we were able to complete the majority of our backlog in well work and had time to analyze the data and more fully assess how we are operating the initial phases of Foster Creek.

Based on this new information, we have made two key observations on the way we operate Foster Creek. First, our wells require more preventative maintenance and improved instrumentation which will allow for increased data collection and monitoring capability and we have improved our liner design, which we expect will improve reliability. The second key observation relates to the evolution of common steam chambers in the initial phases of the project and our need to focus on optimizing the formation of common steam chambers across the field rather than on a well or pad basis. As common steam chambers form, we require different reservoir management processes, which we are assessing. In the near term, we expect to see a higher steam to oil ratio ("SOR") and corresponding reduction in production levels. As we advised in the fourth quarter, we expect to operate Foster Creek phases A through E at a production level of between 100,000 to 110,000 barrels per day in the near term. Fourth quarter 2013 production was in-line with this expectation. Over the long term, we remain confident in the overall magnitude of the resource and the plant deliverability at a SOR consistent with the plant design. As we continue to learn more about operating a SAGD project with one common steam chamber, and build out the remaining phases, we will look to further optimize both the SOR and plant upgrades for the entire facility.

Christina Lake production increased as a result of phase D reaching full capacity, approximately six months after production began in the third quarter of 2012, and phase E production continuing to ramp up as expected after first production in July 2013.

CONDENSATE

The heavy oil and bitumen produced by Cenovus requires the blending of condensate to reduce their viscosity to transport them to market. Revenues include the value of condensate sold as heavy oil blend. The overall value of condensate used in blending increased as a result of higher condensate volumes required for blending and condensate prices increasing two percent, consistent with the increase in the benchmark price.

ROYALTIES

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

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) to the gross revenues from the project. Gross revenues are a function of sales volumes and realized prices.

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

Royalties decreased $55 million during 2013 primarily at Foster Creek related to lower sales volumes, increased annual capital expenditures and higher operating expenses. These changes resulted in a royalty calculation for 2013 based on gross revenues.

Effective Royalty Rates

(percent)	**2013**	2012	2011
Foster Creek	**5.8**	11.8	16.8
Christina Lake	**6.8**	6.2	5.2

Expenses

TRANSPORTATION AND BLENDING

Transportation and blending costs rose $249 million or 17 percent. Blending costs rose as discussed in the Revenues section. Transportation charges were $15 million higher due to production increases and higher sales into the U.S. market which attract higher tariffs, partially offset by volumes shipped on the Trans Mountain pipeline system, on which we have a long-term commitment for firm service since February 2012, resulting in lower transportation charges for our net share.

OPERATING

Primary drivers of our operating costs in 2013 were workforce, fuel costs, workover activities, and repairs and maintenance. In total, operating costs increased $130 million or $1.86 per barrel.

Per-unit Operating Costs

($/bbl)	**2013**	***Percent Change***	2012	*Percent Change*	2011
Foster Creek	**15.77**	**32%**	11.99	6%	11.34
Christina Lake	**12.47**	**(4%)**	12.95	(36%)	20.20

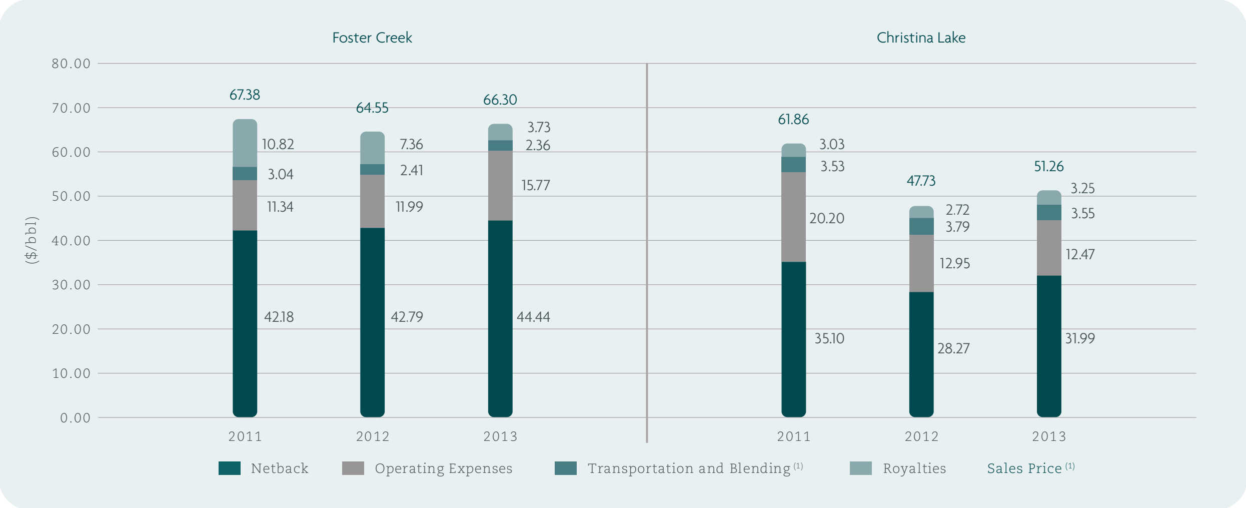
Declining production volumes at Foster Creek contributed to an overall rise in operating costs of $3.78 per barrel. The increase of $55 million was due to:

- Workover activities, as we completed the majority of our backlog in well work as previously discussed;
- Higher fuel prices, consistent with the rising benchmark AECO natural gas price and higher fuel consumption as a result of a higher SOR; and
- Higher workforce costs as we hired additional field staff in advance of the start-up of the phase F expansion expected in the third quarter of 2014.

Christina Lake operating costs decreased $0.48 on a per barrel basis as a result of higher production volumes. The increase of $75 million was due to:

- Increasing fuel usage, as a result of rising production, and higher fuel prices consistent with the benchmark AECO natural gas price;
- Higher costs associated with workforce and fluid, waste handling and trucking costs related to increased production;
- Additional repairs and maintenance costs mainly related to the planned turnaround in the second quarter of 2013; and
- Higher chemical costs due to higher production volumes associated with phase D reaching full capacity early in 2013 and phase E starting up in July, and higher 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 crude oil basis, the cost of condensate in 2013 was $42.41 per barrel (2012 – $41.85 per barrel; 2011 – $41.74 per barrel) for Foster Creek; and $45.25 per barrel (2012 – $45.83 per barrel; 2011 – $47.07 per barrel) for Christina Lake.

RISK MANAGEMENT

Risk management activities resulted in realized gains of $33 million (2012 – gains of $46 million), consistent with our 2013 contract prices exceeding average benchmark prices in 2013.

OIL SANDS – NATURAL GAS

Oil Sands includes our 100 percent owned natural gas operation in Athabasca. Our natural gas production decreased to 21 MMcf per day in 2013 (2012 – 30 MMcf per day) as the result of anticipated natural declines. The internal use of our natural gas production at Foster Creek increased slightly in 2013. Operating Cash Flow was $22 million in 2013 (2012 – $31 million), a 29 percent decrease, primarily due to lower realized gains on risk management, partially offset by decreased operating costs.

OIL SANDS – CAPITAL INVESTMENT

($ millions)	**2013**	2012	2011
Foster Creek	**797**	735	429
Christina Lake	**688**	593	481
	1,485	1,328	910
Narrows Lake	**152**	44	19
Telephone Lake	**93**	138	61
Grand Rapids	**39**	65	31
Other (1)	**114**	118	77
Capital Investment (2)	**1,883**	1,693	1,098

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

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

Existing Projects

2013 capital investment at Foster Creek focused on expansion of phases F, G and H, drilling of sustaining wells, operational improvement projects and infrastructure. Spending also includes the drilling of 112 gross stratigraphic test wells (2012 – 141 gross wells). In 2013, investment increased due to phase H procurement, offsite fabrication and pilings, and phases F and G well pad drilling, construction and pipeline development, partially offset by a reduction in phase F procurement.

2013 Christina Lake capital investment focused on expansion of phases E, F and G, the phase C, D and E optimization program, drilling of sustaining wells, operational improvement projects and infrastructure. Capital investment also included the drilling of 74 gross stratigraphic test wells (2012 – 98 gross wells). In 2013, investment increased primarily due to phase F plant construction, procurement and engineering, and phase E well pad construction and drilling of well pairs, partially offset by lower spending on phase E plant construction, engineering and procurement. In addition, spending commenced for engineering and procurement for the phase C, D and E optimization program which received regulatory approval in 2013.

In 2013, capital investment increased at Narrows Lake due to phase A engineering and procurement, commencement of plant construction in August 2013 and infrastructure costs. Capital investment also included the drilling of 26 gross stratigraphic test wells (2012 – 42 gross wells).

Emerging Projects

At Telephone Lake, our 2013 capital investment was primarily focused on the dewatering pilot. The pilot commenced in the fourth quarter of 2012 and was completed in the fourth quarter of 2013 with the removal and reinjection of water and monitoring of results. We have successfully displaced water with compressed air, displacing approximately 70 percent of below-ground top water. The displaced water was not potable and therefore not suitable for human or other consumption. Capital investment decreased in 2013 with the completion of drilling and facility construction for the dewatering pilot in the third quarter of 2012. Capital investment also included the drilling of 28 stratigraphic test wells (2012 – 29 wells).

Capital investment at Grand Rapids decreased in 2013 due to drilling fewer stratigraphic test wells (2013 – three wells; 2012 – 62 wells). Steam injection started on the second pilot well pair in the third quarter of 2012 and first production was achieved in February 2013. The pilot experienced facility constraints that impacted the production from both well pairs in the first half of 2013. A facility turnaround was performed in the third quarter of 2013 that mitigated these constraints. The purpose of the pilot is to test reservoir performance.

DRILLING ACTIVITY

The stratigraphic test wells drilled at Foster Creek, Christina Lake and Narrows Lake were 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.

To minimize the impact on local infrastructure, the drilling of stratigraphic test wells is primarily completed in the winter months, typically between the end of the fourth quarter and the end of the first quarter. Since 2012, we have been developing the 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. This rig does not require roads for many of its locations and reduces the water, drill cuttings and surface pad size compared with traditional drilling methods. Our first prototype rig has now drilled 42 wells and we are currently constructing a second rig.

The 0.2 billion barrel increase to our economic bitumen best estimate contingent resources resulted from the success of our 2013 stratigraphic test well program converting prospective resources to contingent resources, a net acquisition of contingent resources through a property exchange, offset by the reduction of recovery factors at Steepbank and portions of the Grand Rapids formation and the loss of contingent resources due to the cancellation of mineral rights by the Alberta government for future urban development. Additional information about our resources, including definitions and year end results, is included in the Oil and Gas Reserves and Resources section of this MD&A.

Drilling Activity

	Gross Stratigraphic Test Wells			Gross Production Wells (1)(2)		
	2013	2012	2011	**2013**	2012	2011
Foster Creek	**112**	141	118	**56**	28	21
Christina Lake	**74**	98	93	**35**	32	19
	186	239	211	**91**	60	40
Narrows Lake	**26**	42	47	**–**	–	–
Telephone Lake	**28**	29	40	**–**	–	–
Grand Rapids	**3**	62	59	**–**	1	–
Other	**96**	96	66	**–**	–	3
	339	468	423	**91**	61	43

(1) Includes wells drilled using our Wedge Well™ technology.

(2) SAGD well pairs are counted as a single producing well.

FUTURE CAPITAL INVESTMENT

Expansion work at phases F, G and H at Foster Creek is proceeding as planned. We expect phases F, G and H to each ramp-up to their initial design capacity of 30,000 barrels per day. Once those phases are complete, we anticipate moving ahead with optimization work to lower the SOR, increase production and improve plant efficiency. Total gross production capacity for these phases, including optimization work, is expected to reach 125,000 barrels per day. Production from phase F is expected to start in the third quarter of 2014 with production ramp-up to design capacity expected to take twelve to eighteen months. Production start-up from phases G and H is expected in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015. Upon completion and optimization of production from phases F, G and H, and after ramp-up to initial design capacity of phase J, we believe further optimization opportunities exist to increase total overall plant capacity to over 300,000 barrels per day. Foster Creek capital investment for 2014 is forecast to be between $680 million and $760 million and is primarily focused on expansion phases, sustaining wells, operational improvement projects and infrastructure.

At Christina Lake, phase E development spending for the completion of drilling and well pad and facility construction is expected to continue to the end of 2014. The ramp-up of production from phase E is proceeding as expected with total gross production capacity expected to reach nameplate capacity of 138,000 gross barrels per day in the first quarter of 2014. The phase E ramp-up, similar to the ramp-up of phases C and D, is expected to reach nameplate capacity within six to nine months of first production. Expansion work on phases F, including cogeneration, and G is continuing as planned and we expect to add gross production capacity of 50,000 barrels per day from each phase in 2016 and 2017, respectively. In the third quarter of 2013, we received regulatory approval for the optimization program for Christina Lake phases C, D and E, which is expected to add up to 22,000 barrels per day of gross capacity in 2015. We submitted a joint application and EIA to regulators in March 2013 for the phase H expansion, a 50,000 barrel per day phase for which we expect to receive regulatory approval in the fourth quarter of 2014. Christina Lake capital investment in 2014 is forecast to be between $750 million and $820 million and is primarily focused on expansion phases F and G, the phase C, D and E optimization program, and drilling and facilities work for wedge wells and sustaining wells.

In 2012, we received regulatory approval for Narrows Lake phases A, B and C, and final partner approval for phase A. We are continuing with site construction, engineering and procurement and construction of the phase A plant, which started in the third quarter of 2013. The first phase of the project is anticipated to have a production capacity of 45,000 gross barrels per day, with first oil expected in 2017. Narrows Lake capital investment is forecast to be between $210 million and $230 million in 2014 and is primarily focused on plant construction, procurement and offsite fabrication for the phase A expansion and infrastructure for a construction camp and control room.

Additional capital investment of approximately $140 million to $160 million in 2014 is expected for our emerging SAGD projects and is primarily focused on drilling stratigraphic test wells, front end engineering at Telephone Lake and costs related to the pilot projects at Telephone Lake and Grand Rapids. At Telephone Lake we are advancing the regulatory application for the project and anticipate receiving approval in the second quarter of 2014. The first phase of the project is anticipated to have a production capacity of 90,000 barrels per day. At Grand Rapids we anticipate receiving regulatory approval in the first quarter of 2014 for a 180,000 barrel per day commercial SAGD operation.

DD&A

In 2013, Oil Sands DD&A increased $107 million to $446 million (2012 – $339 million; 2011 – $246 million) due to higher DD&A rates for both of our properties due to higher future development costs associated with total proved reserves and additional sales volumes at Christina Lake, partially offset by lower sales volumes at Foster Creek.

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 and developing tight oil assets in Alberta. This segment also includes the heavy oil assets at Pelican Lake. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced. 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. The cash flow generated in our Conventional operations helps to fund our future growth opportunities in our Oil Sands segment.

Significant factors that impacted our Conventional segment in 2013 compared with 2012 include:

- Crude oil production averaging 76,775 barrels per day, increasing one percent primarily due to successful horizontal well performance in southern Alberta associated with our current drilling program and higher production at Pelican Lake, partially offset by the sale of our Lower Shaunavon asset and expected natural declines; and
- Generating Operating Cash Flow net of capital investment of $621 million, an increase of 23 percent.

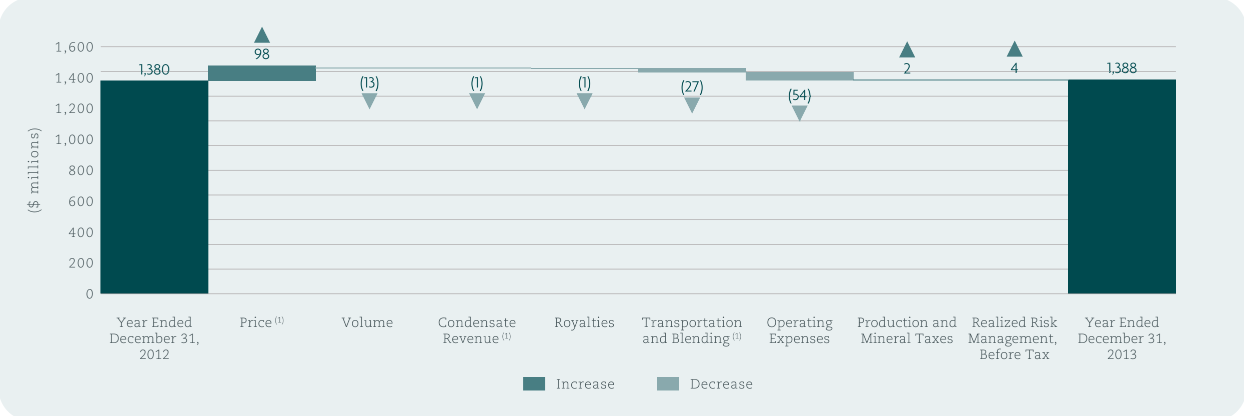
CONVENTIONAL – CRUDE OIL

Financial Results

($ millions)	**2013**	*2012*	*2011*
Gross Sales	**2,373**	2,289	2,124
Less: Royalties	**196**	195	249
Revenues	**2,177**	2,094	1,875
Expenses			
Transportation and Blending	**305**	278	249
Operating	**495**	441	350
Production and Mineral Taxes	**32**	34	27
(Gain) Loss on Risk Management	**(43)**	(39)	63
Operating Cash Flow (1)	**1,388**	1,380	1,186
Capital Investment	**1,169**	1,323	1,003
Operating Cash Flow net of Related Capital Investment	**219**	57	183

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

Operating Cash Flow Variance for the Year Ended December 31, 2013 compared with December 31, 2012



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

Revenues

PRICING

Our average crude oil sales price in 2013 increased five percent to $77.62 per barrel, consistent with the change in crude oil benchmark prices.

PRODUCTION

(barrels per day)	**2013**	***Percent Change***	*2012*	*Percent Change*	*2011*
Pelican Lake	**24,254**	**8%**	22,552	10%	20,424
Other Heavy Oil	**15,991**	**–%**	16,015	2%	15,657
Light and Medium Oil	**35,467**	**(2%)**	36,071	18%	30,524
NGLs	**1,063**	**3%**	1,029	(7%)	1,101
	76,775	**1%**	75,667	12%	67,706

Our crude oil production increased one percent due to strong horizontal well performance in southern Alberta from our current drilling program and higher production at Pelican Lake as a result of additional infill wells coming on stream throughout 2012 and 2013, partially offset by reduced production from the sale of our Lower Shaunavon asset in July 2013 and expected natural declines. In 2013, Lower Shaunavon produced an annual average of 2,095 barrels per day (2012 – 4,411 barrels per day).

CONDENSATE

Revenues include the value of condensate sold as heavy oil blend. The overall value of condensate decreased due to lower condensate prices, partially offset by an increase in the volumes used in blending.

ROYALTIES

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

Royalties increased $1 million primarily due to increased royalties at Pelican Lake as a result of declines in capital investment, an increase in sales volumes and higher prices. Increases in royalties at Pelican Lake were partially offset by lower royalties in our other heavy oil properties due to decreased production volumes.

In 2013, the effective royalty rate at Pelican Lake was 5.9 percent (2012 – 5.0 percent). The effective crude oil royalty rate for our other Conventional properties was 11.0 percent (2012 – 11.8 percent). Our other crude oil producing assets are located primarily on crown or fee land. Production from fee lands results in mineral tax recorded within production and mineral taxes.

Expenses

TRANSPORTATION AND BLENDING

Transportation and blending costs increased $27 million. Transportation costs rose $28 million largely due to the higher cost associated with transporting our light and medium crude oil production by rail. In 2013, we sold approximately 6,150 barrels per day of crude oil that was transported by rail to Canada's East Coast and the U.S. (2012 – 2,600 barrels per day). The overall cost of condensate used in blending decreased as discussed in the Revenues section.

OPERATING

Primary drivers of our operating costs in 2013 were workover activities, workforce costs, electricity, repairs and maintenance and chemical consumption.

Operating costs at Pelican Lake increased $3.57 per barrel to $20.65 per barrel. The total dollar increase of $33 million was associated with:

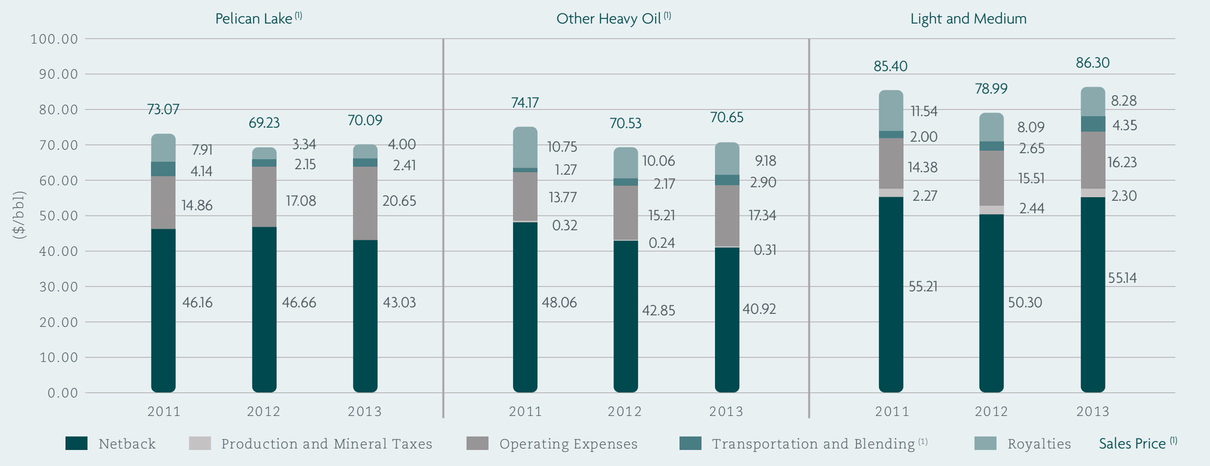
- Higher polymer chemical consumption related to the expansion of the polymer flood program;
- Increased workover and repairs and maintenance activities related to equipment failure; and
- Routine maintenance, and electricity costs from higher market rates and increased consumption.

Operating costs for our other Conventional crude oil properties increased $1.12 per barrel to $16.24 per barrel. The total dollar increase of $21 million was primarily due to:

- Increased workforce costs and increased workover activities associated with high-return well optimizations that helped mitigate production declines; and
- Rising electricity costs from higher market rates.

The cost increases in our other Conventional crude oil operating costs were partially offset by declines in repairs and maintenance due to the sale of Lower Shaunavon and a reduction in road and lease maintenance.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per barrel of unblended crude oil basis, the cost of condensate for Pelican Lake was $15.59 per barrel in 2013 (2012 – $15.55 per barrel; 2011 – $16.32 per barrel) and for our other heavy oil properties was $13.12 per barrel in 2013 (2012 – $13.35 per barrel; 2011 – $12.73 per barrel).

RISK MANAGEMENT

Risk management activities in 2013 resulted in realized gains of $43 million (2012 – gains of $39 million), consistent with our contract prices exceeding the average benchmark prices.

CONVENTIONAL – NATURAL GAS

Financial Results

($ millions)	2013	2012	2011
Gross Sales	**594**	498	825
Less: Royalties	**8**	6	12
Revenues	**586**	492	813
Expenses			
Transportation and Blending	**20**	19	34
Operating	**209**	217	240
Production and Mineral Taxes	**3**	3	9
(Gain) Loss on Risk Management	**(61)**	(229)	(195)
Operating Cash Flow (1)	**415**	482	725
Capital Investment	**22**	43	102
Operating Cash Flow net of Related Capital Investment	**393**	439	623

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

Operating Cash Flow from natural gas net of capital investment decreased $46 million due to lower Operating Cash Flow partially offset by a $21 million reduction in capital investment. Operating Cash Flow from natural gas continues to help fund our growth opportunities in our Oil Sands segment.

Revenues

PRICING

Our average natural gas sales price increased $0.78 per Mcf to $3.20 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

PRODUCTION

Production decreased 10 percent to 508 MMcf per day primarily due to expected natural declines.

ROYALTIES

Royalties increased slightly as a result of higher prices, despite declines in production. The average royalty rate in 2013 was 1.4 percent (2012 – 1.3 percent). Most of our natural gas production is located on fee land. Production from fee lands results in mineral tax recorded within production and mineral taxes.

Expenses

TRANSPORTATION

Transportation costs increased as higher pipeline rates were partially offset by lower production volumes.

OPERATING

Primary drivers of our operating expenses in 2013 were property taxes and lease costs, workforce costs and repairs and maintenance. Operating expenses decreased $8 million in 2013 primarily related to a decrease in workforce and repairs and maintenance expenses as a result of a reduction in our natural gas production.

RISK MANAGEMENT

Risk management activities resulted in realized gains in 2013 of $61 million (2012 – gains of $229 million), consistent with our contract prices exceeding the average benchmark price.

CONVENTIONAL – CAPITAL INVESTMENT (1)

($ millions)	2013	2012	2011
Pelican Lake	**465**	518	317
Other Crude Oil	**704**	805	686
Natural Gas	**22**	43	102
	1,191	1,366	1,105

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

Capital investment in 2013 was composed primarily of spending at Pelican Lake on infill drilling, facilities and maintenance capital associated with the expansion of the polymer flood, and drilling, completion, recompletion programs, and work on our facilities at our other Conventional crude oil assets. Spending on natural gas activities continues to be managed in response to the low natural gas price environment.

Capital investment declined in 2013 primarily due to discontinued spending related to our Lower Shaunavon asset and declines related to Pelican Lake as the rate at which we are expanding the polymer flood slowed to better match our production growth.

In early 2013, we launched a public sales process to divest our Lower Shaunavon asset and certain of our Bakken properties in Saskatchewan. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. In June 2013, we entered into a purchase and sale agreement with an unrelated third party to sell our Lower Shaunavon asset. The sale was completed in July 2013 for proceeds of approximately $240 million plus closing adjustments.

Management decided to discontinue the Bakken sales process until market conditions improve. While discussions with prospective purchasers have occurred, an offer that meets Management's expectations has not been received. As a result of the decision, as at December 31, 2013 the assets and associated decommissioning liabilities were reclassified from held for sale to PP&E and decommissioning liabilities at their carrying amounts. Depletion, calculated on a per-unit of production basis, was recorded in the fourth quarter of 2013. The carrying value continues to be less than the estimated recoverable amount.

FUTURE CAPITAL INVESTMENT

In 2014, Pelican Lake capital investment is forecast to be between $230 million and $250 million with spending mainly focused on infill drilling, pipeline construction and maintenance capital for the polymer flood. The reduction in capital investment from 2013 is due to our decision to align spending with the more moderate production ramp-up associated with the initial results of the polymer flood program.

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

Conventional Drilling Activity

(net wells, unless otherwise stated)	**2013**	2012	2011
Crude Oil	**212**	352	356
Natural Gas	**–**	–	65
Recompletions	**751**	977	1,122
Gross Stratigraphic Test Wells	**54**	19	68

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are mostly related to lower-risk Alberta coal bed methane development that continues to deliver acceptable rates of return. Drilling of stratigraphic test wells increased in 2013 in order to further assess our tight oil plays in Alberta.

DD&A, GOODWILL IMPAIRMENT, EXPLORATION EXPENSE

DD&A

In 2013, Conventional DD&A increased $122 million to $1,170 million (2012 – $1,048 million; 2011 – $879 million) as a result of an increase in the average DD&A rates due to lower proved reserves, in addition to an impairment loss of $57 million related to our Lower Shaunavon asset which was sold in July 2013.

Goodwill Impairment

In 2012, we recognized $393 million of goodwill impairment associated with our Suffield cash-generating unit ("CGU"). The Suffield CGU, including the allocated goodwill, exceeded its fair value less costs of disposal resulting in an impairment that was attributed to goodwill. The impairment resulted primarily due to a decline in natural gas and crude oil prices and increased operating costs. In addition, we had minimal levels of capital spending for natural gas such that production exceeded reserve replacement in the area. There was no goodwill impairment in 2013.

Exploration Expense

In 2013, we recorded total exploration expense of $114 million (2012 – $68 million).

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. As a result of our evaluation of crude oil exploration opportunities, $64 million of pre-exploration expense was recorded in 2013.

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 and we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

In 2013, $50 million (2012 – $68 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 recognized as exploration expense.

REFINING AND MARKETING

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

Significant factors related to our Refining and Marketing segment in 2013 compared with 2012 include:

- Processing 442,000 barrels per day of crude oil, including 222,000 barrels per day of heavy crude oil, resulting in 463,000 barrels per day of refined product output, an increase of seven percent, and a six percent increase in crude utilization. Refined product output last year was reduced due to planned turnarounds at both refineries; and
- Operating Cash Flow decreasing 10 percent to $1,143 million primarily due to declines in market crack spreads and higher costs associated with RINs, partially offset by an improved feedstock cost advantage and increases in refined product output.

REFINERY OPERATIONS [1]

	2013	2012	2011
Crude Oil Capacity [2] *(Mbbls/d)*	**457**	452	452
Crude Oil Runs *(Mbbls/d)*	**442**	412	401
Heavy Crude Oil	**222**	198	126
Light/Medium	**220**	214	275
Crude Utilization *(percent)*	**97**	91	89
Refined Products *(Mbbls/d)*	**463**	433	419
Gasoline	**232**	216	207
Distillate	**144**	138	132
Other	**87**	79	80

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

(2) The official nameplate capacity increased effective January 1, 2014 to 460,000 gross barrels per day.

On a 100 percent basis, our refineries had capacity of approximately 457,000 gross barrels per day of crude oil, excluding NGLs, and 45,000 gross barrels per day of NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. The ability to refine heavy crudes demonstrates our ability to economically integrate our heavy crude oil production.

In 2013, crude oil runs increased seven percent and heavy crude oil runs increased 12 percent. Total refined product output increased by seven percent with the relative proportion of gasoline, distillate and other refined products remaining relatively the same. Planned turnarounds in 2012 reduced output.

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 heavy crude oil, a feedstock cost advantage is created by processing less expensive heavy 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.

FINANCIAL RESULTS

($ millions)	2013	2012	2011
Revenues	**12,706**	11,356	10,625
Purchased Product	**11,004**	9,506	9,149
Gross Margin	**1,702**	1,850	1,476
Expenses			
Operating [1]	**540**	581	475
(Gain) Loss on Risk Management	**19**	(4)	14
Operating Cash Flow [2]	**1,143**	1,273	987
Capital Investment	**107**	118	393
Operating Cash Flow net of Related Capital Investment	**1,036**	1,155	594

(1) We reclassified expenditures related to research activities from operating expenses to research costs.

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

Gross Margin

The gross margin for the Refining and Marketing segment declined $148 million or eight percent as a result of the decline in market crack spreads, consistent with the narrowing of the Brent-WTI differential and higher costs associated with RINs. The decline was partially offset by an improved feedstock cost advantage resulting from processing a higher proportion of discounted heavy crude oil as well as the widening of the WTI-WCS differential and an increase in refined product output.

As part of the U.S. Environmental Protection Agency's ("EPA") Renewable Fuel Standards, refineries in the U.S. are obligated to blend renewable fuels, such as ethanol, into petroleum-based motor fuel products at rates determined by the EPA. To the extent they do not, refineries 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.

We are obligated to purchase RINs in the open market as our refineries do not blend renewable fuels into gasoline and diesel products. In 2013, our RINs cost was $153 million, an increase of $121 million reflecting the $0.55 per barrel increase in the ethanol RINs price, as a result of the change in the EPA's mandated blending quotas for 2013. Despite the recent increase in costs associated with RINs, these costs remain a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating costs in 2013 were labour, maintenance, utilities and supplies. Operating costs were lower by $41 million or seven percent as 2012 planned maintenance activities resulted in higher costs.

Operating Cash Flow

Operating Cash Flow from the Refining and Marketing segment declined $130 million or 10 percent from 2012 primarily due to the decrease in gross margin, partially offset by lower operating costs.

REFINING AND MARKETING – CAPITAL INVESTMENT

($ millions)	**2013**	2012	2011
Wood River Refinery	**64**	54	346
Borger Refinery	**42**	64	45
Marketing	**1**	–	2
	107	118	393

Capital expenditures in 2013 focused on capital maintenance and refinery reliability and safety projects. In 2012, capital investment was reduced by Illinois tax credits of $14 million related to capital expenditures incurred at the Wood River Refinery in prior periods.

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

DD&A

In 2013, Refining and Marketing DD&A decreased $8 million to $138 million (2012 – $146 million; 2011 – $130 million) primarily due to the change in foreign exchange rates.

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 2013, our risk management activities resulted in $415 million of unrealized losses, before tax (2012 – $57 million of unrealized gains, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

($ millions)	**2013**	2012	2011
General and Administrative	**349**	350	295
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Foreign Exchange (Gain) Loss, Net	**208**	(20)	26
Research Costs	**24**	15	8
(Gain) Loss on Divestiture of Assets	**1**	–	(107)
Other (Income) Loss, Net	**2**	(5)	4
	1,017	686	549

Expenses

GENERAL AND ADMINISTRATIVE

Primary drivers of our general and administrative expenses in 2013 were workforce, office rent and information technology costs. General and administrative expenses decreased $1 million, remaining relatively flat from 2012, primarily due to lower long-term incentive costs partially offset by rent increases and higher staffing costs.

RESEARCH COSTS

Both technology development, including research activities, and the environment are playing increasingly larger roles in all aspects of our business.

In 2013, we reclassified 2012 and 2011 research costs from operating expenses in our Consolidated Statements of Earnings and Comprehensive Income to conform with current presentation. There were no changes to Net Earnings as a result. Research costs increased $9 million in 2013 compared with 2012, as a result of our increased focus on research activities which provide important information on how we will manage our operations.

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. In 2013, finance costs were $74 million higher than in 2012 due to a full year of interest incurred on our senior unsecured notes issued in August 2012 and a US$32 million premium paid on the early redemption of the US$800 million of senior unsecured notes that were due in September 2014. Increases were partially offset by lower interest incurred on the Partnership Contribution Payable as the balance continues to be repaid. The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for 2013 was 5.2 percent (2012 – 5.3 percent).

INTEREST INCOME

Interest income includes interest earned on our short-term investments and U.S. dollar denominated Partnership Contribution Receivable. In 2013, interest income decreased by $13 million consistent with lower interest earned on the Partnership Contribution Receivable as the balance was collected over the course of the year.

FOREIGN EXCHANGE

($ millions)	**2013**	*2012*	*2011*
Unrealized Foreign Exchange (Gain) Loss	**40**	(70)	(42)
Realized Foreign Exchange (Gain) Loss	**168**	50	68
	208	(20)	26

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, 2013, offset by the reversal of the previously recognized unrealized losses on the U.S. dollar Partnership Contribution Receivable.

Realized losses resulted primarily from the receipt of the remaining principal of the Partnership Contribution Receivable on December 17, 2013, partially offset by a realized foreign exchange gain of $33 million recorded on the early redemption of the US$800 million senior unsecured notes that were to mature September 2014.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. DD&A for 2013 was $79 million (2012 – $52 million; 2011 – $40 million) an increase of $27 million, due to the depreciation of our new office space leaseholds starting in October 2012.

INCOME TAX EXPENSE

($ millions)	2013	2012	2011
Current Tax			
Canada	**143**	188	150
U.S.	**45**	121	4
Total Current Tax	**188**	309	154
Deferred Tax	**244**	474	575
	432	783	729

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

($ millions, except percent amounts)	2013	2012	2011
Earnings Before Income Tax	**1,094**	1,778	2,207
Canadian Statutory Rate	**25.2%**	25.2%	26.7%
Expected Income Tax	**276**	448	589
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**109**	146	82
Non-deductible Stock-based Compensation	**10**	10	18
Multi-jurisdictional Financing	**(22)**	(27)	(50)
Foreign Exchange Gain (Loss), not Included in Net Earnings	**19**	14	(9)
Non-taxable Capital (Gains) Losses	**31**	(7)	(8)
Derecognition (Recognition) of Capital Losses	**15**	(22)	26
Adjustments Arising From Prior Year Tax Filings	**(13)**	33	31
Withholding Tax on Foreign Dividends	**–**	68	–
Goodwill Impairment	**–**	99	–
Other	**7**	21	50
Total Tax	**432**	783	729
Effective Tax Rate	**39.5%**	44.0%	33.0%

The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation. In 2013, current taxes decreased $121 million primarily due to $68 million of withholding tax on a U.S. dividend in 2012, adjustments related to a change in legislation of $24 million, the finalization of our 2012 tax filings, and lower taxable U.S. earnings in the current year. The decrease in deferred tax is primarily due to unrealized risk management losses compared to gains in 2012 and lower earnings before tax from U.S. sources resulting in lower utilization of tax loss pools compared to 2012.

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 in 2013 when compared to 2012 is primarily due to the non-deductible charge for a goodwill impairment and the U.S. withholding tax in 2012, partially offset by non-deductible foreign exchange losses, derecognition of capital losses and a significant increase in 2013 in the proportion of income in the higher tax rate U.S. jurisdiction relative to the lower tax rate Canadian jurisdiction.

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.

QUARTERLY RESULTS

($ millions, except per share amounts or where otherwise indicated)	**Q4 2013**	**Q3 2013**	**Q2 2013**	**Q1 2013**	Q4 2012	Q3 2012	Q2 2012	Q1 2012	Q4 2011
Production Volumes									
Crude Oil *(bbls/d)*	**188,743**	**176,938**	**171,127**	**180,225**	177,646	171,350	155,566	156,850	144,273
Natural Gas *(MMcf/d)*	**514**	**523**	**536**	**545**	566	577	596	636	660
Revenues	**4,747**	**5,075**	**4,516**	**4,319**	3,724	4,340	4,214	4,564	4,329
Operating Cash Flow (1) (2)	**976**	**1,153**	**1,125**	**1,214**	966	1,314	1,081	1,090	1,021
Cash Flow (1)	**835**	**932**	**871**	**971**	697	1,117	925	904	851
Per Share – Diluted	**1.10**	**1.23**	**1.15**	**1.28**	0.92	1.47	1.22	1.19	1.12
Operating Earnings (Loss) (1) (3)	**212**	**313**	**255**	**391**	(188)	432	284	340	332
Per Share – Diluted (3)	**0.28**	**0.41**	**0.34**	**0.52**	(0.25)	0.57	0.37	0.45	0.44
Net Earnings (Loss) (3)	**(58)**	**370**	**179**	**171**	(117)	289	397	426	266
Per Share – Basic (3)	**(0.08)**	**0.49**	**0.24**	**0.23**	(0.15)	0.38	0.53	0.56	0.35
Per Share – Diluted (3)	**(0.08)**	**0.49**	**0.24**	**0.23**	(0.15)	0.38	0.52	0.56	0.35
Capital Investment (4)	**898**	**743**	**706**	**915**	978	830	660	900	903
Cash Dividends	**183**	**182**	**183**	**184**	167	166	166	166	151
Per Share	**0.242**	**0.242**	**0.242**	**0.242**	0.22	0.22	0.22	0.22	0.20

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

(2) For all periods presented, we reclassified expenditures related to research activities from operating expenses to research costs increasing Operating Cash Flow. There were no changes to Cash Flow, Operating Earnings or Net Earnings.

(3) We restated prior periods as a result of adoption of new accounting standards. See Critical Accounting Judgments, Estimates and Accounting Policies within this MD&A for more details.

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

Our quarterly results over the last eight quarters were impacted primarily by rising crude oil production volumes and fluctuations in commodity prices.

FOURTH QUARTER 2013 RESULTS AS COMPARED TO THE FOURTH QUARTER 2012

Total crude oil production rose six percent, with the most significant increase at Christina Lake (rising 47 percent). Crude oil sales prices decreased one percent, consistent with the widening of the average WTI-WCS differential in the fourth quarter of 2013 to US$32.20 per barrel compared with US$18.11 per barrel for the same period last year.

Natural gas production in the fourth quarter of 2013 was 514 MMcf per day, a decrease of nine percent, mainly due to expected declines in production from limited capital investment.

Our refining operations processed an average of 447,000 (2012 – 311,000) gross barrels per day of crude oil, of which 221,000 gross barrels per day was heavy crude oil (2012 – 155,000). We produced 469,000 gross barrels per day of refined products, an increase of about 139,000 gross barrels per day or 42 percent, as refined product output in the fourth quarter of 2012 was impacted by planned turnarounds at both refineries.

Operating Cash Flow

Operating Cash Flow increased $10 million, or one percent, remaining relatively flat compared with 2012. Refining and Marketing Operating Cash Flow of $151 million increased 23 percent primarily due to an improved feedstock cost advantage and higher refined product output, partially offset by sharp declines in market crack spreads and increased costs associated with RINs. Upstream Operating Cash Flow of $825 million declined two percent primarily due to higher crude oil operating costs, an increase of $2.13 per barrel, realized risk management gains before tax of $67 million compared with gains of $102 million in 2012 and lower natural gas production volumes, partially offset by rising crude oil production.

Cash Flow

While Operating Cash Flow was relatively unchanged from 2012, our Cash Flow increased $138 million in the fourth quarter of 2013 primarily due to a decrease in current tax expense of $122 million mainly related to $68 million of withholding tax incurred on the payment of a U.S. dividend in 2012 and a difference in the recognition of Canadian partnership income for tax purposes.

Operating Earnings (Loss)

In addition to changes impacting Cash Flow, Operating Earnings increased $400 million in the fourth quarter of 2013 as compared to the same period in 2012. The increase was primarily due to a goodwill impairment of $393 million recorded in 2012 in our Conventional segment. Increases in Operating Earnings were partially offset by rising DD&A, as a result of higher production and higher DD&A rates, and an increase in deferred tax expense, excluding tax on unrealized risk management (gains) losses and non-operating unrealized foreign exchange (gains) losses, due to the reversal of Canadian temporary differences from increased earnings in Canada.

Net Earnings (Loss)

In the fourth quarter of 2013, our net loss was $58 million, compared to a net loss of $117 million in the same period last year. Our net loss decreased $59 million as a result of the increase in Operating Earnings discussed above, partially offset by unrealized risk management losses, after-tax, of $163 million compared with gains of $87 million in the fourth quarter of 2012 and a realized foreign exchange loss of $146 million, after-tax, related to the receipt of the remaining principal on the Partnership Contribution Receivable.

Capital Investment

Capital investment in the fourth quarter of 2013 was $898 million, a decrease of $80 million from the same period in 2012 due to declines in spending primarily in our Conventional segment. The fourth quarter was focused on the development of our expansion phases at Foster Creek and Christina Lake, and construction on phase A of Narrows 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 CBM reserves and 100 percent of our bitumen contingent and prospective resources. Our AIF 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").

Highlights in 2013 compared with 2012 include:

- Proved bitumen reserves increased eight percent and proved plus probable bitumen reserves increased six percent.
  - Christina Lake added proved reserves of 82 million barrels while proved plus probable reserves increased by 28 million barrels. Increases at Christina Lake were as a result of receiving approval to expand the development area and planned increases to future well density. Foster Creek added proved reserves of 67 million barrels and proved plus probable reserves of 16 million barrels. Increases at Foster Creek were a result of development area expansion. Increases were also due to well downspacing at Christina Lake and Narrows Lake.
- Heavy oil proved reserves decreased three percent and proved plus probable heavy oil reserves increased 10 percent. These changes were as a result of revised Pelican Lake development plans to drill more infill wells and expand polymer flood areas using increased well density.
- Light and medium crude oil and NGLs proved reserves remained unchanged and proved plus probable reserves decreased by four percent, as a result of additions being offset by production and the Lower Shaunavon divestiture.
- Natural gas proved reserves declined nine percent and proved plus probable reserves decreased 10 percent as additions and improved performance at Brooks North were more than offset by production.
- Bitumen best estimate economic contingent resources increased 0.2 billion barrels or two percent while bitumen best estimate prospective resources declined 1.0 billion barrels or 12 percent. Factors impacting the results include:
  - Stratigraphic test well drilling successfully converting prospective resources to contingent resources;
  - A property exchange resulting in the net acquisition of contingent resources and the net divestiture of prospective resources;
  - The reduction of recovery factors at Steepbank and portions of the Grand Rapids formation; and
  - The loss of contingent and prospective resources due to the cancellation of mineral rights by the Alberta government for future urban development.

The reserves and resources data that follows is presented as at December 31, 2013 using McDaniel & Associates Consultants Ltd. ("McDaniel's") January 1, 2014 forecast prices and costs. Comparative information as at December 31, 2012 uses McDaniel's January 1, 2013 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

As at December 31, 2013	*Bitumen (MMbbls)*		*Heavy Oil (MMbbls)*		*Light & Medium Oil & NGLs (MMbbls)*		*Natural Gas & CBM (Bcf)*	
Before Royalties	**2013**	2012	**2013**	2012	**2013**	2012	**2013**	2012
Proved	**1,846**	1,717	**179**	184	**115**	115	**865**	955
Probable	**683**	676	**140**	105	**50**	56	**300**	338
Proved plus Probable	**2,529**	2,393	**319**	289	**165**	171	**1,165**	1,293

RECONCILIATION OF PROVED RESERVES

Before Royalties	*Bitumen (MMbbls)*	*Heavy Oil (MMbbls)*	*Light & Medium Oil & NGLs (MMbbls)*	*Natural Gas & CBM (Bcf)*
December 31, 2012	**1,717**	**184**	**115**	**955**
Extensions and Improved Recovery	**134**	**21**	**11**	**24**
Discoveries	**–**	**–**	**–**	**–**
Technical Revisions	**32**	**(12)**	**6**	**76**
Economic Factors	**–**	**–**	**–**	**–**
Acquisitions	**–**	**–**	**–**	**–**
Dispositions	**–**	**–**	**(5)**	**–**
Production	**(37)**	**(14)**	**(12)**	**(190)**
December 31, 2013	**1,846**	**179**	**115**	**865**
Year Over Year Change	**129**	**(5)**	**–**	**(90)**
	8%	**(3%)**	**0%**	**(9%)**

RECONCILIATION OF PROBABLE RESERVES

Before Royalties	*Bitumen (MMbbls)*	*Heavy Oil (MMbbls)*	*Light & Medium Oil & NGLs (MMbbls)*	*Natural Gas & CBM (Bcf)*
December 31, 2012	**676**	**105**	**56**	**338**
Extensions and Improved Recovery	**28**	**55**	**–**	**5**
Discoveries	**78**	**–**	**–**	**–**
Technical Revisions	**(99)**	**(20)**	**(4)**	**(43)**
Economic Factors	**–**	**–**	**–**	**–**
Acquisitions	**–**	**–**	**–**	**–**
Dispositions	**–**	**–**	**(2)**	**–**
Production	**–**	**–**	**–**	**–**
December 31, 2013	**683**	**140**	**50**	**300**
Year Over Year Change	**7**	**35**	**(6)**	**(38)**
	1%	**33%**	**(11%)**	**(11%)**

ECONOMIC CONTINGENT RESOURCES AND PROSPECTIVE RESOURCES

As at December 31, (billions of barrels, before royalties)	*Bitumen* **2013**	2012
Economic Contingent Resources (1)		
Best Estimate	**9.8**	9.6
Prospective Resources (1)(2)		
Best Estimate	**7.5**	8.5

(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, 2013.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2013	2012	2011
Net Cash From (Used In)			
Operating Activities	**3,539**	3,420	3,273
Investing Activities	**(1,519)**	(3,336)	(2,530)
Net Cash Provided (Used) Before Financing Activities	**2,020**	84	743
Financing Activities	**(726)**	592	(558)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(2)**	(11)	10
Increase in Cash and Cash Equivalents	**1,292**	665	195

At December 31, 2013, we had cash and cash equivalents of $2.5 billion, no amounts were drawn on our committed credit facility and no commercial paper was outstanding.

OPERATING ACTIVITIES

Cash from operating activities was $119 million higher in 2013 mainly due to the change in non-cash working capital, partially offset by the decrease in Cash Flow as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $1,957 million at December 31, 2013 compared with $1,043 million at December 31, 2012. We anticipate that we will continue to meet our payment obligations as they come due.

INVESTING ACTIVITIES

In 2013, cash used in investing activities was $1,519 million, a $1,817 million decrease from 2012. The reduction was predominately due to the receipt of the remaining principal of the Partnership Contribution Receivable in December 2013. In addition, proceeds of $258 million on the sale of our Lower Shaunavon asset and other minor assets increased cash from investing activities.

FINANCING ACTIVITIES

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment, then to paying a meaningful dividend and finally to growth capital. In 2013, we paid a dividend of $0.968 per share (2012 – $0.88 per share). Total dividend payments in 2013 were $732 million (2012 – $665 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash used in financing activities in 2013 increased $1,318 million from 2012 primarily as a result of the issuance and repayment of debt. On August 15, 2013, we completed a public offering in the U.S. in aggregate of US$800 million senior unsecured notes under our U.S. base shelf prospectus. The notes were issued in two tranches, US$450 million of senior unsecured notes with a coupon rate of 3.8 percent due September 15, 2023 and US$350 million of senior unsecured notes with a coupon rate of 5.2 percent due September 15, 2043. The net proceeds of the offering were used to partially fund the early redemption of our US$800 million senior unsecured notes due September 2014. The offering allowed us to secure favourable interest rates, eliminate our 2014 re-financing risk and extend the weighted average term to maturity of our long-term debt.

In 2012, we completed a public offering in the U.S. of senior unsecured notes in the aggregate principal amount of US$1.25 billion under our U.S. base shelf prospectus. We issued US$500 million of senior unsecured notes with a coupon rate of 3.00 percent due August 15, 2022 and US$750 million of senior unsecured notes with a coupon rate of 4.45 percent due September 15, 2042. The net proceeds were used for general corporate purposes, including repayment of commercial paper indebtedness.

Our long-term debt at December 31, 2013, was $4,997 million with no principal payments due until October 2019 (US$1.3 billion). The $318 million increase in long-term debt from December 31, 2012 was due to fluctuations in foreign exchange rates.

As at December 31, 2013, we are in compliance with all of the terms of our debt agreements.

AVAILABLE SOURCES OF LIQUIDITY

We expect cash flow from our crude oil, natural gas and refining operations to fund a significant portion of our cash requirements over the next decade. Any potential shortfalls may be required to be funded through financing activities or management of our asset portfolio. The following sources of liquidity are available as at December 31, 2013.

($ millions)	*Amount*	*Term*
Cash and Cash Equivalents	**2,452**	**Not applicable**
Committed Credit Facility	**3,000**	**November 2017**
Canadian Base Shelf Prospectus [1]	**1,500**	**June 2014**
U.S. Base Shelf Prospectus [1]	**US$1,200**	**July 2014**

(1) Availability is subject to market conditions.

Our cash and cash equivalents balance at December 31, 2013 includes US$1.4 billion related to the December 17, 2013 receipt of the remaining principal of the Partnership Contribution Receivable.

Committed Credit Facility

In September 2013, we renegotiated our existing $3.0 billion committed credit facility, extending the maturity date from November 30, 2016 to November 30, 2017.

We also have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve capacity under our committed credit facility for amounts of outstanding commercial paper. As of December 31, 2013, no amounts were drawn on our committed credit facility and there was no commercial paper outstanding.

Canadian Base Shelf Prospectus

On May 24, 2012, we filed a Canadian base shelf prospectus for unsecured medium-term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium-term notes in Canadian dollars or other foreign currencies from time to time, in one or more offerings, with availability subject to market conditions. Terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. The Canadian base shelf prospectus expires in June 2014. It is our intention to file a new Canadian shelf prospectus prior to the maturity of the existing Canadian shelf prospectus.

As at December 31, 2013, no medium-term notes were issued under this Canadian shelf prospectus.

U.S. Base Shelf Prospectus

On May 9, 2013, we amended our U.S. base shelf prospectus for senior unsecured notes to increase the total capacity from US$2.0 billion to US$3.25 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies from time to time, in one or more offerings, with availability subject to market conditions. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. The U.S. base shelf prospectus expires in July 2014. It is our intention to file a new U.S. shelf prospectus prior to the maturity of the existing U.S. shelf prospectus.

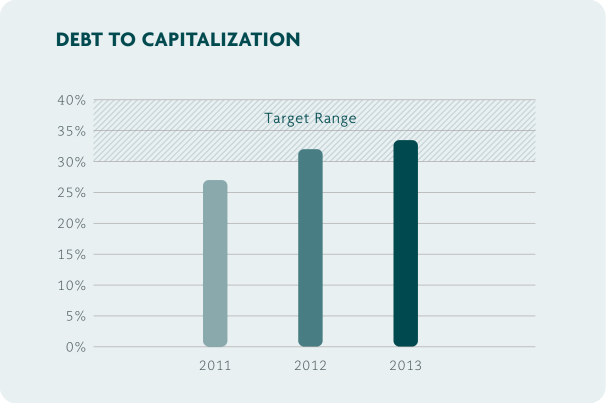
As at December 31, 2013, US$1.2 billion remains available under our U.S. base shelf prospectus, the availability of which is dependent on market conditions.

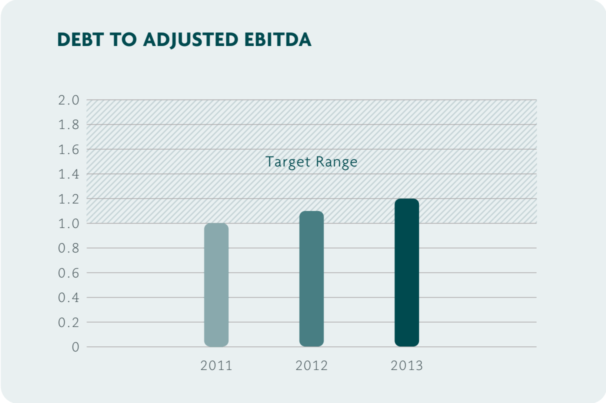
FINANCIAL METRICS

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

	2013	2012	2011
Debt to Capitalization	**33%**	32%	27%
Debt to Adjusted EBITDA *(times)*	**1.2x**	1.1x	1.0x

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, 2013, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges.





Debt to Capitalization is calculated as follows:

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Shareholders' Equity	**9,946**	9,782	9,384
Capitalization	**14,943**	14,461	12,911
Debt to Capitalization	**33%**	32%	27%

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

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Net Earnings	**662**	995	1,478
Add (Deduct):			
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Income Tax Expense	**432**	783	729
DD&A	**1,833**	1,585	1,295
Goodwill Impairment	**–**	393	–
E&E Impairment	**50**	68	–
Unrealized (Gain) Loss on Risk Management	**415**	(57)	(180)
Foreign Exchange (Gain) Loss, Net	**208**	(20)	26
(Gain) Loss on Divestiture of Assets	**1**	–	(107)
Other (Income) Loss, Net	**2**	(5)	4
Adjusted EBITDA	**4,036**	4,088	3,568
Debt to Adjusted EBITDA	**1.2x**	1.1x	1.0x

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, an unlimited number of first preferred shares and an unlimited number of second preferred shares. At December 31, 2013, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of Cenovus.

In addition to its Stock Option Plan, Cenovus has a performance share unit ("PSU") plan and two deferred share unit ("DSU") plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. Refer to note 28 of the Consolidated Financial Statements for more details.

Total Outstanding Common Shares and Stock-Based Compensation Plans

As at December 31, 2013	***Units*** *(thousands)*
Common Shares	**756,046**
Stock Options	
NSRs	**26,315**
TSARs	**7,086**
Cenovus Replacement TSARs	**1,479**
Encana Replacement TSARs	**3,904**
Other Stock-Based Compensation Plans	
PSUs	**5,785**
DSUs	**1,192**

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)	*2014*	*2015*	*2016*	*2017*	*2018*	*Thereafter*	*Total*
Operating							
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
Other Long-term Commitments	50	40	21	17	12	116	256
Interest on Long-term Debt	271	268	268	268	268	3,682	5,025
Interest on Partnership Contribution Payable	82	55	26	2	–	–	165
Decommissioning Liabilities	104	105	113	117	116	6,916	7,471
Total Operating	1,101	1,161	1,199	1,329	1,839	31,176	37,805
Investing							
Capital Commitments	52	36	30	9	21	27	175
Partnership Contribution Payable	438	465	494	128	–	–	1,525
Total Investing	490	501	524	137	21	27	1,700
Financing							
Long-term Debt (principal only)	–	–	–	–	–	5,052	5,052
Total Financing	–	–	–	–	–	5,052	5,052
Total Payments [2]	1,591	1,662	1,723	1,466	1,860	36,255	44,557
Fixed Price Product Sales	52	54	56	3	–	–	165

(1) Certain transportation commitments included are subject to regulatory approval.

(2) Contracts on behalf of the 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, Cenovus is responsible for the field operations, marketing and transportation of 100 percent of the production from these assets. Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements, debt, future building leases, marketing agreements and capital commitments. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the Consolidated Financial Statements.

In 2013, Cenovus entered into various firm transportation agreements totaling approximately $11 billion. These agreements, most of which are subject to regulatory approval, are for terms 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 shipping capacity to approximately 10,000 barrels per day by the end of 2013. We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions.

As at December 31, 2013, Cenovus remained a party to long-term, fixed price, physical contracts for natural gas with a current delivery of approximately 33 MMcf per day, with varying terms and volumes through 2017. The total volume to be delivered within the terms of these contracts is 37 Bcf of natural gas, at a weighted average price of $4.43 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 year ended December 31, 2013 or 2012. For a summary of key Management compensation refer to the notes to the Consolidated Financial Statements.

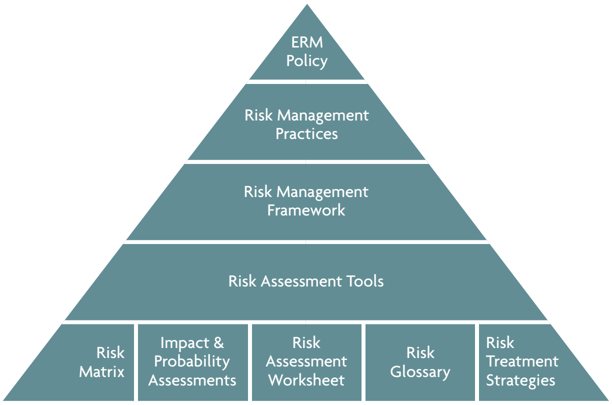
RISK MANAGEMENT

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 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 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 elevating these exposures to the right decision makers.

RISK MANAGEMENT ROLES AND RESPONSIBILITIES

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

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 resulting from the inability to adequately plan or implement an appropriate business strategy, or to adapt 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 safety, the environment, transportation restrictions, project execution and reserves replacement; 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, 2013.

The following explains how some of the 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 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, NGLs, 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.

We anticipate commodity prices and refining margins will continue to be volatile over the next few years. If crude oil and natural gas prices decline significantly and remained at low levels for an extended period of time, the carrying value of our assets may be subject to impairment, future capital programs could 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.

We manage our commodity price exposure through a combination of activities including 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.

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 one other Executive Vice-President. These activities are governed through our Market Risk Mitigation Policy, which contains prescribed hedging protocols and limits. In 2013, we partially mitigated our exposure to the following:

- Crude oil commodity price risk on our crude oil sales with fixed price commodity swaps;
- Natural gas commodity price risk on our natural gas sales with fixed price swaps;
- Widening location or quality differentials for crude oil and natural gas 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

	2013			2012		
($ millions)	***Realized***	***Unrealized***	***Total***	*Realized*	*Unrealized*	*Total*
Crude Oil	**(71)**	**343**	**272**	(81)	(247)	(328)
Natural Gas	**(63)**	**69**	**6**	(247)	176	(71)
Refining	**18**	**–**	**18**	(7)	(1)	(8)
Power	**(6)**	**3**	**(3)**	(1)	15	14
(Gain) Loss on Risk Management	**(122)**	**415**	**293**	(336)	(57)	(393)
Income Tax Expense (Recovery)	**29**	**(105)**	**(76)**	86	14	100
(Gain) Loss on Risk Management, after-tax	**(93)**	**310**	**217**	(250)	(43)	(293)

In 2013, 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 recognized unrealized losses as a result of the increase in forward commodity prices compared with prices at the end of the prior year and changes in prices for transactions executed during the year, as well as the realization of settled positions, partially offset by the widening of forward light/heavy differentials.

Financial instruments undertaken within our refining segment by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the 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 hedges using fixed-price swap contracts to reduce our commodity price risk on a portion of our expected 2014 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, 2013 as follows:

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)**
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 depressed economic times or due to unforeseen events, Cenovus's 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, 2013, we had cash and cash equivalents of $2.5 billion, no amounts were drawn on our 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$1.2 billion in unused capacity under our U.S. base shelf prospectus, the availability of which are dependent on market conditions.

We believe that our current liquidity position is sufficient to protect us in the near-term 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.

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 control safety, security 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 realized 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 position, results of operations and cash flows within our Oil Sands and Conventional segments.

To help mitigate these risks, we employ a diversified sales strategy which includes utilizing multiple transportation options, including pipeline, railcar, and cargo. In addition to the firm transportation commitments we have made to date, we continue to evaluate our options and may make further commitments to new and expanding transportation infrastructure to enable access to additional markets for our production.

We anticipate transportation constraints will continue in the near term. The Keystone XL project, the Northern Gateway Pipeline 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. Currently, the Keystone XL project will connect Alberta's oil sands with refineries in the U.S. Gulf Coast, the Northern Gateway Pipeline project will connect Alberta's oil sands to Canada's West Coast, allowing for transportation to new markets such as Asia, and the Energy East Pipeline project will 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 next 10 years, 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. 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.

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 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. 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 position, 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 10-year 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, 2013.

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 government 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 have been put in place and 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 regulation 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.

Water Use Impacts

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 costs 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 costs 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 2013 Carbon Disclosure Leadership Index for Canada. 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 EPA 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, 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 in order to meet the requirements. Our financial conditions, 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 in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan. The Government of Alberta approved its 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 compensation of $20 million, including interest, 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.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

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

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 recognized 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 recognized in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, 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 costs, as well as estimated economically recoverable reserves are considered. If it is determined that an E&E asset is not technically feasible or commercially viable and 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 recognized 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.

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 have a significant impact on the impairment test and DD&A expense of Cenovus's crude oil and natural gas assets in the Oil Sands and Conventional segments. Cenovus's crude oil and natural gas reserves are evaluated and reported to Cenovus by IQREs.

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 costs. Recoverable amounts for Cenovus's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating costs, 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.

At December 31, 2013, 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 reserves as estimated by Cenovus's IQREs, crude oil and natural gas prices and the discount rate.

CRUDE OIL AND NATURAL GAS PRICES

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

	2014	2015	2016	2017	2018	*Average Annual % Change to 2024*
WTI (US$/barrel)	95.00	95.00	95.00	95.00	95.30	1.9%
AECO ($/Mcf)	4.00	4.25	4.55	4.75	5.00	2.4%

DISCOUNT RATE

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent, which is common industry practice, and used by our 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 the economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recognized 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 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 recognized 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.

CHANGES IN ACCOUNTING POLICIES

We adopted the following new standards and amendments to standards:

Joint Arrangements, Consolidation, Associates and Disclosures

Effective January 1, 2013, we adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to International Accounting Standard ("IAS") 28, "*Investments in Associates and Joint Ventures*" ("IAS 28").

IFRS 10 revised the definition of control to include three elements: (1) power over an investee; (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. Cenovus reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees.

Under IFRS 11, a joint arrangement is classified as either a joint operation or a joint venture depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method. Cenovus performed a comprehensive review of its interest in other entities and identified two individually significant interests, FCCL and WRB, for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal form of the separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of our accounting policy under IFRS 11 requires judgment in determining the classification of these joint arrangements. A discussion of the judgments used in our assessment of joint arrangements can be found in the Consolidated Financial Statements. 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. There has been no impact on the recognized assets, liabilities and comprehensive income of Cenovus with the application of IFRS 11.

IFRS 12 requires disclosures relating to an entity's interest in subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 28 was amended to conform to the changes made in IFRS 10 and IFRS 11. The adoption of IFRS 12 and IAS 28 did not result in any changes to disclosures.

Employee Benefits

Effective January 1, 2013, we adopted, as required, IAS 19, "*Employee Benefits*", as amended in June 2011 ("IAS 19R"). We applied the standard retrospectively and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

IAS 19R requires the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor' approach previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through other comprehensive income ("OCI"). In addition, we replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability measured by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period. Interest expense and interest income on net post-employment benefit liabilities and assets continue to be recognized in Net Earnings.

Furthermore, termination benefits must be recognized at the earlier of when the entity can no longer withdraw an offer of termination benefits or recognizes any restructuring costs.

The effect on the Consolidated Balance Sheets of IAS 19R was:

As at January 1, 2012	*Net Defined Benefit Liability* [(1)]	*Deferred Income Taxes*	*Shareholders' Equity*
Balance as Previously Reported	16	2,101	9,406
Effect of Adoption of IAS 19R	30	(8)	(22)
Restated Balance	46	2,093	9,384

(1) Composed of the defined benefit pension and other post-employment benefit plans ("OPEB") plans, which are included in other liabilities on the Consolidated Balance Sheets of the Consolidated Financial Statements.

As at December 31, 2012	*Net Defined Benefit Liability* [(1)]	*Deferred Income Taxes*	*Shareholders' Equity*
Balance as Previously Reported	28	2,568	9,806
Effect of Adoption of IAS 19R	32	(8)	(24)
Restated Balance	60	2,560	9,782

(1) Composed of the defined benefit pension and OPEB plans, which are included in other liabilities on the Consolidated Balance Sheets of the Consolidated Financial Statements.

The effect on the Consolidated Statements of Earnings and Comprehensive Income of IAS 19R was:

	Year Ended December 31, 2012	*Year Ended December 31, 2011*
Decrease in General and Administrative Expense	2	–
Increase in Net Earnings for the Year	2	–
Remeasurement of Defined Benefit and OPEB Liabilities	(4)	(12)
(Decrease) in Comprehensive Income for the Period	(2)	(12)

The change in accounting policy did not have a material impact on the Consolidated Financial Statements including Net Earnings per Share.

Details about our pension and OPEB plans are disclosed in the Consolidated Financial Statements.

Fair Value Measurement

Effective January 1, 2013, we adopted, as required, IFRS 13, "*Fair Value Measurement*" ("IFRS 13") and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to Cenovus's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013. The disclosures related to fair value measurement can be found in Note 32 to the Consolidated Financial Statements.

Presentation of Items in Other Comprehensive Income

Effective January 1, 2013, we applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within OCI to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to OCI or comprehensive income.

Disclosure of Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2013, we complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. The additional disclosures can be found in the Consolidated Financial Statements. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets of the Consolidated Financial Statements.

Disclosures of Recoverable Amounts of Non-Financial Assets

In May 2013, the IASB issued an amendment to IAS 36, "*Impairment of Assets*". The amendment removes certain disclosures of the recoverable amount of a CGU. The amendment is effective retrospectively for annual periods beginning on or after January 1, 2014. As allowed by the standard, we have early adopted the amendment in the current period. Refer to the notes to the Consolidated Financial Statements for the amended disclosures.

FUTURE ACCOUNTING PRONOUNCEMENTS

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning on or after January 1, 2014 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2013. The standards and interpretations applicable to Cenovus are as follows and will be adopted on their respective effective dates:

Financial Instruments

The IASB intends to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

For financial assets, IFRS 9 uses 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 in IFRS 9 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.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. We do not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

Offsetting Financial Assets and Financial Liabilities

In December 2011, the IASB issued amendments to IAS 32, "*Financial Instruments: Presentation*" ("IAS 32"), to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact 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, 2013. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2013.

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, 2013.

There have been no changes to ICFR during the year ended December 31, 2013 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 strategy 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 will not compromise the health and 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 2012 CR report in July 2013, 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 January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index (see below). 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. Corporate Knights also recognized Cenovus's leading CR performance in their inaugural Top 10 Energy Companies in the World listing, published in November 2013.

In October 2013, we were named to the Canada 200 Climate Disclosure Leadership Index for the fourth 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 2013, our leading CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the second consecutive year. We were also named to the Dow Jones Sustainability North America Index for the fourth consecutive year. In June 2013, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the second year in a row and for the third consecutive year by Corporate Knights magazine as one of the 2013 Best 50 Corporate Citizens in Canada.

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

OUTLOOK

We continue to move forward on our 10-year business plan targeting net oil sands bitumen production of approximately 435,000 barrels per day and net crude oil production, including our conventional oil operations, of approximately 525,000 barrels per day by the end of 2023. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Telephone Lake and Grand Rapids. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach. This approach will be enabled by technology, innovation and continued respect for the health and safety of our employees and contractors, with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Our pricing outlook is influenced by the following:

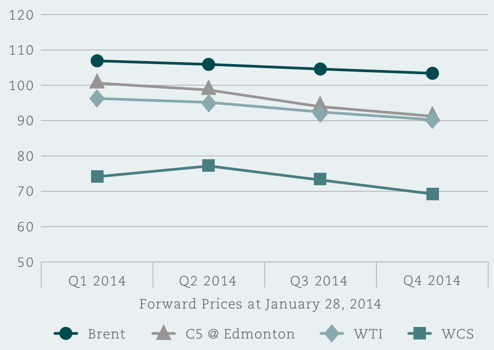
- We expect the general outlook for crude oil prices will continue to be tied to global economic growth, the pace of North American supply growth and production interruptions. Indicators suggest a continued gradual improvement in demand growth from both U.S. and Asian markets. North American supply growth is expected to continue at a strong, but moderating pace. Global supply disruptions are difficult to predict; however, we believe political instability, which is the root cause of supply outages, is unlikely to be resolved quickly. The overall expectation is for a modest decline in Brent crude oil prices in 2014 compared with 2013;
- The Brent-WTI differential is expected to narrow from 2013 as new pipeline capacity from Cushing to the Gulf Coast reduces inland congestion, partially offset by increased discounts of Gulf Coast crude oil prices relative to Brent crude oil prices as growing tight oil supply reduces the need for imports;
- We expect 2014 WTI-WCS price differentials to remain near 2013 levels as growing inland supply will approximate growth in pipeline and rail shipping capacity;
- Average Refining crack spreads in 2014 are expected to strengthen compared with 2013, mostly due to declines in WTI prices relative to Brent prices;
- Natural gas prices are expected to strengthen compared with 2013 as the pace of demand growth increases and storage inventories are reduced by late-2013 cold weather, partially offset by rising supply growth as new infrastructure is added to high-growth areas; and
- Based on forward prices, the Canadian dollar has weakened approximately seven percent from US\$0.953/C\$1 in the fourth quarter to a forward average of about US\$0.890/C\$1 for 2014. The weakening of the Canadian dollar has a positive impact on our revenues and Operating Cash Flow.

While we expect to see volatility in crude prices, we mitigate our exposure to light/heavy price differentials through the following:

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

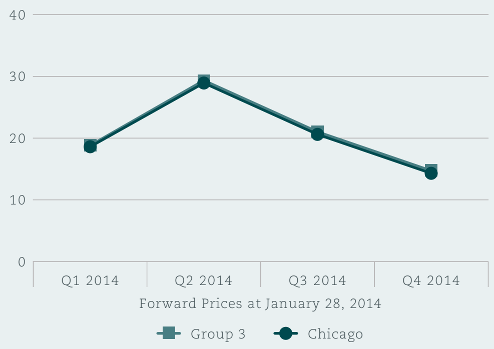
CRUDE OIL BENCHMARKS

(Average US$/bbl)



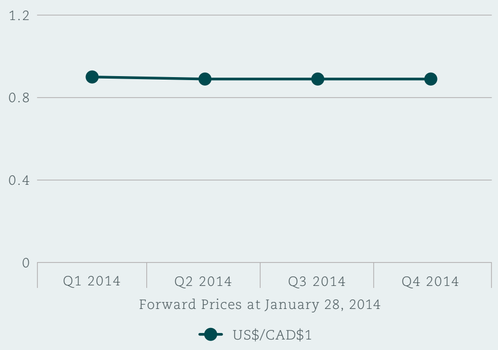
REFINING 3-2-1 CRACK SPREAD BENCHMARKS

(Average US$/bbl)



FOREIGN EXCHANGE

(Average US$/CAD$1)



KEY PRIORITIES FOR 2014

Our key priorities for 2014 remain unchanged from 2013.

Market Access

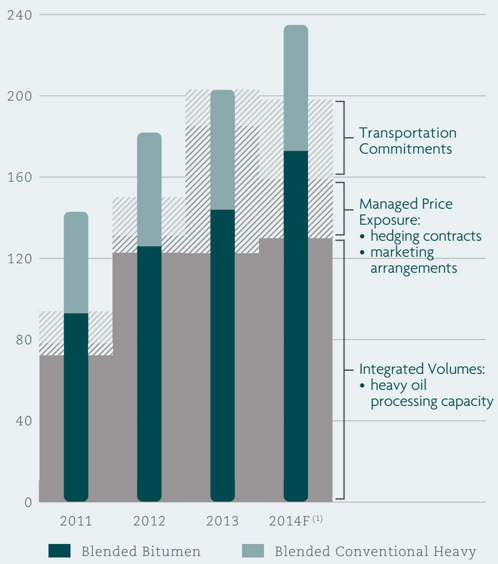
We are focused on near and mid-term strategies to broaden market access for our crude oil production. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions, by supporting industry transportation projects as well as new and expanded market development initiatives for our crude oil. During 2013, we entered into approximately $11 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.

Attacking Cost Structures

We continue to take aim at cost structures across the organization to maintain our track record of cost efficiency. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we are actively identifying opportunities in supply chain management to further reduce capital and operating costs.

PROTECTION AGAINST CANADIAN CONGESTION

(Mbbls/d)



(1) Expected gross production capacity.

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, 2013
(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, 2013. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") framework in Internal Control – Integrated Framework (1992) 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, 2013.

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, 2013, as stated in their Auditor's Report dated February 12, 2014. 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 12, 2014

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF CENOVUS ENERGY INC.

We have completed an integrated audit of Cenovus Energy Inc.'s 2013, 2012 and 2011 Consolidated Financial Statements and its internal control over financial reporting as at December 31, 2013. 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, 2013, December 31, 2012 and January 1, 2012 and the Consolidated Statements of Earnings and Comprehensive Income, Shareholders' Equity and Cash Flows for each of the three years ended December 31, 2013, 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, 2013, December 31, 2012 and January 1, 2012 and its financial performance and cash flows for each of the three years in the period ended December 31, 2013 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

OTHER MATTER

As discussed in Note 4 to the Consolidated Financial Statements, Cenovus Energy Inc. changed its method of accounting for employee benefits.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

We have also audited Cenovus Energy Inc.'s internal control over financial reporting as at December 31, 2013, based on criteria established in Internal Control – Integrated Framework (1992), 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, 2013 based on criteria established in Internal Control – Integrated Framework (1992), issued by COSO.

PricewaterhouseCoopers LLP

PRICEWATERHOUSECOOPERS LLP

Chartered Accountants
Calgary, Alberta, Canada

February 12, 2014

CONSOLIDATED STATEMENTS OF EARNINGS AND COMPREHENSIVE INCOME

For the years ended December 31, *($ millions, except per share amounts)*	Notes	2013	2012	2011
			(Note 4)	(Note 4)
Revenues	1			
Gross Sales		**18,993**	17,229	16,185
Less: Royalties		**336**	387	489
		18,657	16,842	15,696
Expenses	1			
Purchased Product		**10,399**	9,223	9,090
Transportation and Blending		**2,074**	1,798	1,369
Operating		**1,798**	1,667	1,398
Production and Mineral Taxes		**35**	37	36
(Gain) Loss on Risk Management	32	**293**	(393)	(248)
Depreciation, Depletion and Amortization	17, 18	**1,833**	1,585	1,295
Goodwill Impairment	20	**–**	393	–
Exploration Expense		**114**	68	–
General and Administrative		**349**	350	295
Finance Costs	6	**529**	455	447
Interest Income	7	**(96)**	(109)	(124)
Foreign Exchange (Gain) Loss, Net	8	**208**	(20)	26
Research Costs		**24**	15	8
(Gain) Loss on Divestiture of Assets	18	**1**	–	(107)
Other (Income) Loss, Net		**2**	(5)	4
Earnings Before Income Tax		**1,094**	1,778	2,207
Income Tax Expense	9	**432**	783	729
Net Earnings		**662**	995	1,478
Other Comprehensive Income (Loss), Net of Tax				
Items that Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**14**	(4)	(12)
Items that May be Subsequently Reclassified to Profit or Loss:				
Change in Value of Available for Sale Financial Assets		**10**	–	–
Foreign Currency Translation Adjustment		**117**	(24)	48
Total Other Comprehensive Income (Loss), Net of Tax		**141**	(28)	36
Comprehensive Income		**803**	967	1,514
Net Earnings Per Common Share	10			
Basic		**$ 0.88**	$ 1.32	$ 1.96
Diluted		**$ 0.87**	$ 1.31	$ 1.95

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at *($ millions)*	*Notes*	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
			(Note 4)	(Note 4)
Assets				
Current Assets				
Cash and Cash Equivalents	11	**2,452**	1,160	495
Accounts Receivable and Accrued Revenues	12	**1,874**	1,464	1,405
Income Tax Receivable		**15**	–	–
Current Portion of Partnership Contribution Receivable	13	**–**	384	372
Inventories	14	**1,259**	1,288	1,291
Risk Management	32	**10**	283	232
Assets Held for Sale	15	**–**	–	116
Current Assets		**5,610**	4,579	3,911
Exploration and Evaluation Assets	1, 16	**1,473**	1,285	880
Property, Plant and Equipment, Net	1, 17	**17,334**	16,152	14,324
Partnership Contribution Receivable	13	**–**	1,398	1,822
Risk Management	32	**–**	5	52
Income Tax Receivable		**–**	–	29
Other Assets	19	**68**	58	44
Goodwill	1, 20	**739**	739	1,132
Total Assets		**25,224**	24,216	22,194
Liabilities and Shareholders' Equity				
Current Liabilities				
Accounts Payable and Accrued Liabilities	21	**2,937**	2,650	2,579
Income Tax Payable		**268**	217	329
Current Portion of Partnership Contribution Payable	13	**438**	386	372
Risk Management	32	**136**	17	54
Liabilities Related to Assets Held for Sale	15	**–**	–	54
Current Liabilities		**3,779**	3,270	3,388
Long-Term Debt	22	**4,997**	4,679	3,527
Partnership Contribution Payable	13	**1,087**	1,426	1,853
Risk Management	32	**3**	1	14
Decommissioning Liabilities	23	**2,370**	2,315	1,777
Other Liabilities	24	**180**	183	158
Deferred Income Taxes	9	**2,862**	2,560	2,093
Total Liabilities		**15,278**	14,434	12,810
Shareholders' Equity		**9,946**	9,782	9,384
Total Liabilities and Shareholders' Equity		**25,224**	24,216	22,194

Commitments and Contingencies 35

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 26)	(Note 26)		(Note 27)	
Balance as at January 1, 2011, as Previously Reported	3,716	4,083	525	71	8,395
Cumulative Effect of Change in Accounting Policy (Note 4)	–	–	–	(10)	(10)
Balance as at January 1, 2011, Restated	3,716	4,083	525	61	8,385
Net Earnings	–	–	1,478	–	1,478
Other Comprehensive Income (Loss)	–	–	–	36	36
Total Comprehensive Income (Loss)	–	–	1,478	36	1,514
Common Shares Issued Under Option Plans	64	–	–	–	64
Stock-Based Compensation Expense	–	24	–	–	24
Dividends on Common Shares	–	–	(603)	–	(603)
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 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 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**

(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*	**2013**	2012	2011
Operating Activities				
Net Earnings		**662**	995	1,478
Depreciation, Depletion and Amortization		**1,833**	1,585	1,295
Goodwill Impairment		**–**	393	–
Exploration Expense		**50**	68	–
Deferred Income Taxes	9	**244**	474	575
Cash Tax on Divestiture of Assets		**–**	–	13
Unrealized (Gain) Loss on Risk Management	32	**415**	(57)	(180)
Unrealized Foreign Exchange (Gain) Loss	8	**40**	(70)	(42)
(Gain) Loss on Divestiture of Assets		**1**	–	(107)
Unwinding of Discount on Decommissioning Liabilities	6, 23	**97**	86	75
Other		**267**	169	169
		3,609	3,643	3,276
Net Change in Other Assets and Liabilities		**(120)**	(113)	(82)
Net Change in Non-Cash Working Capital		**50**	(110)	79
Cash From Operating Activities		**3,539**	3,420	3,273
Investing Activities				
Capital Expenditures – Exploration and Evaluation Assets	16	**(331)**	(654)	(527)
Capital Expenditures – Property, Plant and Equipment	17	**(2,938)**	(2,795)	(2,265)
Proceeds From Divestiture of Assets		**258**	76	173
Cash Tax on Divestiture of Assets		**–**	–	(13)
Net Change in Investments and Other	13	**1,486**	(13)	(28)
Net Change in Non-Cash Working Capital		**6**	50	130
Cash (Used in) Investing Activities		**(1,519)**	(3,336)	(2,530)
Net Cash Provided (Used) before Financing Activities		**2,020**	84	743
Financing Activities				
Net Issuance (Repayment) of Short-Term Borrowings		**(8)**	3	(9)
Issuance of U.S. Unsecured Notes	22	**814**	1,219	–
Repayment of U.S. Unsecured Notes	22	**(825)**	–	–
Proceeds on Issuance of Common Shares		**28**	37	48
Dividends Paid on Common Shares	10	**(732)**	(665)	(603)
Other		**(3)**	(2)	6
Cash From (Used in) Financing Activities		**(726)**	592	(558)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(2)**	(11)	10
Increase (Decrease) in Cash and Cash Equivalents		**1,292**	665	195
Cash and Cash Equivalents, Beginning of Year		**1,160**	495	300
Cash and Cash Equivalents, End of Year		**2,452**	1,160	495
Supplementary Cash Flow Information	34			

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, 2013

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 began independent operations on December 1, 2009, as a result of the plan of arrangement ("Arrangement") involving Encana Corporation ("Encana") whereby Encana was split into two independent energy companies, one a natural gas company, Encana, and the other an oil company, Cenovus. In connection with the Arrangement, Encana common shareholders received one share in each of the new Encana and Cenovus in exchange for each Encana share held.

Cenovus was 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 focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.
- **Corporate and Eliminations**, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, research costs and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

The operating and reportable segments shown above have been changed from those presented in prior periods to match Cenovus's new operating structure. All prior periods have been restated to reflect this presentation. As a result, for the years ended December 31, 2012 and 2011, segment income of $275 million and $204 million, respectively, was reclassified from Oil Sands to Conventional. In addition to the restatement required due to changes in operating segments, research activities previously included in operating expense have been reclassified to conform to the presentation adopted for the year ended December 31, 2013.

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,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**3,912**	3,356	2,659	**2,980**	2,800	2,960	**12,706**	11,356	10,625
Less: Royalties	**132**	186	228	**204**	201	261	**–**	–	–
	3,780	3,170	2,431	**2,776**	2,599	2,699	**12,706**	11,356	10,625
Expenses									
Purchased Product	**–**	–	–	**–**	–	–	**11,004**	9,506	9,149
Transportation and Blending	**1,749**	1,501	1,086	**325**	297	283	**–**	–	–
Operating	**555**	426	330	**708**	662	594	**540**	581	475
Production and Mineral Taxes	**–**	–	–	**35**	37	36	**–**	–	–
(Gain) Loss on Risk Management	**(37)**	(64)	50	**(104)**	(268)	(132)	**19**	(4)	14
Operating Cash Flow	**1,513**	1,307	965	**1,812**	1,871	1,918	**1,143**	1,273	987
Depreciation, Depletion and Amortization	**446**	339	246	**1,170**	1,048	879	**138**	146	130
Goodwill Impairment	**–**	–	–	**–**	393	–	**–**	–	–
Exploration Expense	**–**	–	–	**114**	68	–	**–**	–	–
Segment Income (Loss)	**1,067**	968	719	**528**	362	1,039	**1,005**	1,127	857

	Corporate and Eliminations			*Consolidated*		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Revenues						
Gross Sales	**(605)**	(283)	(59)	**18,993**	17,229	16,185
Less: Royalties	**–**	–	–	**336**	387	489
	(605)	(283)	(59)	**18,657**	16,842	15,696
Expenses						
Purchased Product	**(605)**	(283)	(59)	**10,399**	9,223	9,090
Transportation and Blending	**–**	–	–	**2,074**	1,798	1,369
Operating	**(5)**	(2)	(1)	**1,798**	1,667	1,398
Production and Mineral Taxes	**–**	–	–	**35**	37	36
(Gain) Loss on Risk Management	**415**	(57)	(180)	**293**	(393)	(248)
	(410)	59	181	**4,058**	4,510	4,051
Depreciation, Depletion and Amortization	**79**	52	40	**1,833**	1,585	1,295
Goodwill Impairment	**–**	–	–	**–**	393	–
Exploration Expense	**–**	–	–	**114**	68	–
Segment Income (Loss)	**(489)**	7	141	**2,111**	2,464	2,756
General and Administrative	**349**	350	295	**349**	350	295
Finance Costs	**529**	455	447	**529**	455	447
Interest Income	**(96)**	(109)	(124)	**(96)**	(109)	(124)
Foreign Exchange (Gain) Loss, Net	**208**	(20)	26	**208**	(20)	26
Research Costs	**24**	15	8	**24**	15	8
(Gain) Loss on Divestiture of Assets	**1**	–	(107)	**1**	–	(107)
Other (Income) Loss, Net	**2**	(5)	4	**2**	(5)	4
	1,017	686	549	**1,017**	686	549
Earnings Before Income Tax				**1,094**	1,778	2,207
Income Tax Expense				**432**	783	729
Net Earnings				**662**	995	1,478

B) FINANCIAL RESULTS BY UPSTREAM PRODUCT

	Crude Oil [1]								
	Oil Sands			**Conventional**			**Total**		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**3,850**	3,307	2,585	**2,373**	2,289	2,124	**6,223**	5,596	4,709
Less: Royalties	**131**	186	226	**196**	195	249	**327**	381	475
	3,719	3,121	2,359	**2,177**	2,094	1,875	**5,896**	5,215	4,234
Expenses									
Transportation and Blending	**1,748**	1,499	1,084	**305**	278	249	**2,053**	1,777	1,333
Operating	**531**	401	303	**495**	441	350	**1,026**	842	653
Production and Mineral Taxes	**–**	–	–	**32**	34	27	**32**	34	27
(Gain) Loss on Risk Management	**(33)**	(46)	67	**(43)**	(39)	63	**(76)**	(85)	130
Operating Cash Flow	**1,473**	1,267	905	**1,388**	1,380	1,186	**2,861**	2,647	2,091

(1) Includes NGLs.

	Natural Gas								
	Oil Sands			**Conventional**			**Total**		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**38**	38	63	**594**	498	825	**632**	536	888
Less: Royalties	**1**	–	2	**8**	6	12	**9**	6	14
	37	38	61	**586**	492	813	**623**	530	874
Expenses									
Transportation and Blending	**1**	2	2	**20**	19	34	**21**	21	36
Operating	**18**	23	24	**209**	217	240	**227**	240	264
Production and Mineral Taxes	**–**	–	–	**3**	3	9	**3**	3	9
(Gain) Loss on Risk Management	**(4)**	(18)	(17)	**(61)**	(229)	(195)	**(65)**	(247)	(212)
Operating Cash Flow	**22**	31	52	**415**	482	725	**437**	513	777

	Other								
	Oil Sands			**Conventional**			**Total**		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**24**	11	11	**13**	13	11	**37**	24	22
Less: Royalties	**–**	–	–	**–**	–	–	**–**	–	–
	24	11	11	**13**	13	11	**37**	24	22
Expenses									
Transportation and Blending	**–**	–	–	**–**	–	–	**–**	–	–
Operating	**6**	2	3	**4**	4	4	**10**	6	7
Production and Mineral Taxes	**–**	–	–	**–**	–	–	**–**	–	–
(Gain) Loss on Risk Management	**–**	–	–	**–**	–	–	**–**	–	–
Operating Cash Flow	**18**	9	8	**9**	9	7	**27**	18	15

	Total Upstream								
	Oil Sands			**Conventional**			**Total**		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Revenues									
Gross Sales	**3,912**	3,356	2,659	**2,980**	2,800	2,960	**6,892**	6,156	5,619
Less: Royalties	**132**	186	228	**204**	201	261	**336**	387	489
	3,780	3,170	2,431	**2,776**	2,599	2,699	**6,556**	5,769	5,130
Expenses									
Transportation and Blending	**1,749**	1,501	1,086	**325**	297	283	**2,074**	1,798	1,369
Operating	**555**	426	330	**708**	662	594	**1,263**	1,088	924
Production and Mineral Taxes	**–**	–	–	**35**	37	36	**35**	37	36
(Gain) Loss on Risk Management	**(37)**	(64)	50	**(104)**	(268)	(132)	**(141)**	(332)	(82)
Operating Cash Flow	**1,513**	1,307	965	**1,812**	1,871	1,918	**3,325**	3,178	2,883

C) GEOGRAPHIC INFORMATION

For the years ended December 31,	*Canada* 2013	2012	2011	*United States* 2013	2012	2011	*Consolidated* 2013	2012	2011
Revenues									
Gross Sales	**8,943**	8,069	7,513	**10,050**	9,160	8,672	**18,993**	17,229	16,185
Less: Royalties	**336**	387	489	**–**	–	–	**336**	387	489
	8,607	7,682	7,024	**10,050**	9,160	8,672	**18,657**	16,842	15,696
Expenses									
Purchased Product	**2,022**	1,884	1,867	**8,377**	7,339	7,223	**10,399**	9,223	9,090
Transportation and Blending	**2,074**	1,798	1,369	**–**	–	–	**2,074**	1,798	1,369
Operating	**1,276**	1,108	944	**522**	559	454	**1,798**	1,667	1,398
Production and Mineral Taxes	**35**	37	36	**–**	–	–	**35**	37	36
(Gain) Loss on Risk Management	**275**	(385)	(255)	**18**	(8)	7	**293**	(393)	(248)
	2,925	3,240	3,063	**1,133**	1,270	988	**4,058**	4,510	4,051
Depreciation, Depletion and Amortization	**1,695**	1,439	1,165	**138**	146	130	**1,833**	1,585	1,295
Goodwill Impairment	**–**	393	–	**–**	–	–	**–**	393	–
Exploration Expense	**114**	68	–	**–**	–	–	**114**	68	–
Segment Income (Loss)	**1,116**	1,340	1,898	**995**	1,124	858	**2,111**	2,464	2,756

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 $926 million (2012 – $671 million; 2011 – $700 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, 2013, Cenovus had three customers (2012 – three; 2011 – two) 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 $7,032 million, $2,711 million and $1,799 million, respectively (2012 – $3,928 million, $3,300 million, and $2,839 million; 2011 – $7,324 million and $2,683 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, 2013 was $1,383 million and $1,144 million, respectively (2012 – $1,188 million and $1,274 million; 2011 – $967 million and $981 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, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Oil Sands	**1,313**	1,064	699	**7,401**	6,041	4,897
Conventional	**160**	221	181	**6,291**	6,652	5,995
Refining and Marketing	**–**	–	–	**3,269**	3,088	3,200
Corporate and Eliminations	**–**	–	–	**373**	371	232
Consolidated	**1,473**	1,285	880	**17,334**	16,152	14,324

	Goodwill			Total Assets		
As at	**December 31, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Oil Sands	**242**	242	242	**9,549**	9,658	8,578
Conventional	**497**	497	890	**7,235**	7,618	7,512
Refining and Marketing	**–**	–	–	**5,491**	5,018	4,927
Corporate and Eliminations	**–**	–	–	**2,949**	1,922	1,177
Consolidated	**739**	739	1,132	**25,224**	24,216	22,194

(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, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Canada	**1,473**	1,285	880	**14,066**	13,065	11,124
United States	**–**	–	–	**3,268**	3,087	3,200
Consolidated	**1,473**	1,285	880	**17,334**	16,152	14,324

	Goodwill			Total Assets		
As at	**December 31, 2013**	December 31, 2012	January 1, 2012	**December 31, 2013**	December 31, 2012	January 1, 2012
Canada	**739**	739	1,132	**20,548**	19,744	17,536
United States	**–**	–	–	**4,676**	4,472	4,658
Consolidated	**739**	739	1,132	**25,224**	24,216	22,194

F) CAPITAL EXPENDITURES [1]

For the years ended December 31,	**2013**	2012	2011
Capital			
Oil Sands	**1,883**	1,693	1,098
Conventional	**1,191**	1,366	1,105
Refining and Marketing	**107**	118	393
Corporate	**81**	191	127
	3,262	3,368	2,723
Acquisition Capital			
Oil Sands [2]	**27**	69	40
Conventional	**5**	45	29
Corporate	**–**	–	2
	3,294	3,482	2,794

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

(2) 2012 asset acquisition included the assumption of a decommissioning liability of $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 12, 2014.

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 the power to govern their financial and operating policies. 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 and 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 recognized in net earnings.
- 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 recognized in net earnings.
- 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.

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 GROUP) 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/area/project 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, and 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, 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 estimated future 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 as estimated by 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 flow 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.

The Company's consolidated financial assets include cash and cash equivalents, accounts receivable and accrued revenues, partner loans receivable, the Partnership Contribution Receivable, risk management assets and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, partner loans payable, 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, partner loans receivable, the Partnership Contribution Receivable 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, partner loans payable, 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 2013.

X) RECENT ACCOUNTING PRONOUNCEMENTS

New Standards and Interpretations not yet Adopted

A number of new standards, amendments to standards and interpretations are effective for annual periods beginning on or after January 1, 2014 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2013. The standards and interpretations applicable to the Company are as follows and will be adopted on their respective effective dates:

FINANCIAL INSTRUMENTS

The IASB intends to replace International Accounting Standard 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39") with IFRS 9, "*Financial Instruments*" ("IFRS 9"). IFRS 9 will be published in three phases, of which two phases have been published.

Phases one and two address accounting for financial assets and financial liabilities, and hedge accounting, respectively. The third phase will address impairment of financial instruments.

For financial assets, IFRS 9 uses 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 in IFRS 9 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.

IFRS 9 introduces a simplified hedge accounting model, aligning hedge accounting more closely with risk management. In addition, improvements have been made to hedge accounting and risk management disclosure requirements. Cenovus does not currently apply hedge accounting.

A mandatory effective date for IFRS 9 in its entirety will be announced when the project is closer to completion. Early adoption of the two completed phases is permitted only if adopted in their entirety at the beginning of a fiscal period. The Company is currently evaluating the impact of adopting IFRS 9 on the Consolidated Financial Statements.

OFFSETTING FINANCIAL ASSETS AND FINANCIAL LIABILITIES

In December 2011, the IASB issued amendments to IAS 32, "*Financial Instruments: Presentation*" ("IAS 32"), to clarify the requirements for offsetting financial assets and liabilities. The amendments clarify that the right to offset must be available on the current date and cannot be contingent on a future event. The amendments to IAS 32 are effective for annual periods beginning on or after January 1, 2014, requiring retrospective application. IAS 32 will not have a significant impact on the Consolidated Financial Statements.

4. CHANGE IN ACCOUNTING POLICIES

New and Amended Standards Adopted

The Company adopted the following new standards and amendments to standards:

JOINT ARRANGEMENTS, CONSOLIDATION, ASSOCIATES AND DISCLOSURES

Effective January 1, 2013, the Company adopted, as required, IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10"), IFRS 11, "*Joint Arrangements*" ("IFRS 11"), IFRS 12, "*Disclosure of Interests in Other Entities*" ("IFRS 12") as well as the amendments to IAS 28, "*Investments in Associates and Joint Ventures*" ("IAS 28").

IFRS 10 revised the definition of control to include three elements: (1) power over an investee; (2) exposure to variable returns from its involvement with the investee and (3) the ability to use its power to affect returns from the investee. Cenovus reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change in the consolidation status of its subsidiaries and investees.

Under IFRS 11, a joint arrangement is classified as either a joint operation or a joint venture depending on the rights and obligations of the parties to the arrangement. Under a joint operation, parties have rights to the assets and obligations for the liabilities of the arrangement and account for their share of assets, liabilities, revenues and expenses. Under a joint venture, parties have the rights to the net assets of the arrangement and account for the arrangement as an investment using the equity method. Cenovus performed a comprehensive review of its interest in other entities and identified two individually significant interests, FCCL and WRB, for which it shares joint control. Cenovus reviewed these joint arrangements considering their structure, the legal form of the separate vehicles, the contractual terms of the arrangements and other facts and circumstances. The application of the Company's accounting policy under IFRS 11 requires judgment in determining the classification of these joint arrangements. A discussion of the judgments used in the Company's assessment of its joint arrangements can be found in Note 5. 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. There has been no impact on the recognized assets, liabilities and comprehensive income of the Company with the application of IFRS 11.

IFRS 12 requires disclosures relating to an entity's interest in subsidiaries, joint arrangements, associates and unconsolidated structured entities. IAS 28 was amended to conform to the changes made in IFRS 10 and IFRS 11. The adoption of IFRS 12 and IAS 28 did not result in any changes to disclosures.

EMPLOYEE BENEFITS

Effective January 1, 2013, the Company adopted, as required, IAS 19, *"Employee Benefits"*, as amended in June 2011 ("IAS 19R"). The Company applied the standard retrospectively and in accordance with the transitional provisions. The opening Consolidated Balance Sheet of the earliest comparative period presented (January 1, 2012) was restated.

IAS 19R requires the recognition of changes in defined benefit pension obligations and plan assets when they occur, eliminating the 'corridor' approach previously permitted and accelerating the recognition of past service costs. In order for the net defined benefit liability or asset to reflect the full value of the plan deficit or surplus, all actuarial gains and losses are recognized immediately through OCI. In addition, the Company replaced interest costs on the defined benefit obligation and the expected return on plan assets with a net interest cost based on the net defined benefit asset or liability measured by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period. Interest expense and interest income on net post-employment benefit liabilities and assets continue to be recognized in net earnings.

Furthermore, termination benefits must be recognized at the earlier of when the entity can no longer withdraw an offer of termination benefits or recognizes any restructuring costs.

The effect on the Consolidated Balance Sheets of IAS 19R was:

As at January 1, 2012	*Net Defined Benefit Liability* [1]	*Deferred Income Taxes*	*Shareholders' Equity*
Balance as Previously Reported	16	2,101	9,406
Effect of Adoption of IAS 19R	30	(8)	(22)
Restated Balance	46	2,093	9,384

(1) Composed of the defined benefit pension and OPEB plans, which are included in other liabilities on the Consolidated Balance Sheets.

As at December 31, 2012	*Net Defined Benefit Liability* [1]	*Deferred Income Taxes*	*Shareholders' Equity*
Balance as Previously Reported	28	2,568	9,806
Effect of Adoption of IAS 19R	32	(8)	(24)
Restated Balance	60	2,560	9,782

(1) Composed of the defined benefit pension and OPEB plans, which are included in other liabilities on the Consolidated Balance Sheets.

The effect on the Consolidated Statements of Earnings and Comprehensive Income of IAS 19R was:

	Year Ended December 31, 2012	*Year Ended December 31, 2011*
Decrease in General and Administrative Expense	2	–
Increase in Net Earnings for the Year	2	–
Remeasurement of Defined Benefit and OPEB Liabilities	(4)	(12)
(Decrease) in Comprehensive Income for the Year	(2)	(12)

The change in accounting policy did not have a material impact on the Consolidated Financial Statements including net earnings per share.

Details about the Company's pension and OPEB plans are disclosed in Note 25.

FAIR VALUE MEASUREMENT

Effective January 1, 2013, the Company adopted, as required, IFRS 13, "*Fair Value Measurement*" ("IFRS 13") and applied the standard prospectively as required by the transitional provisions. The standard provides a consistent definition of fair value and introduces consistent requirements for disclosures related to fair value measurement. There has been no change to Cenovus's methodology for determining the fair value for its financial assets and liabilities and, as such, the adoption of IFRS 13 did not result in any measurement adjustments as at January 1, 2013. The disclosures related to fair value measurement can be found in Note 32.

PRESENTATION OF ITEMS IN OTHER COMPREHENSIVE INCOME

Effective January 1, 2013, the Company applied the amendment to IAS 1, "*Presentation of Financial Statements*" ("IAS 1"), as amended in June 2011. The amendment requires items within OCI to be grouped into two categories: (1) items that will not be subsequently reclassified to profit or loss or (2) items that may be subsequently reclassified to profit or loss when specific conditions are met. The amendment has been applied retrospectively and, as such, the presentation of items in OCI has been modified. The application of the amendment to IAS 1 did not result in any adjustments to OCI.

DISCLOSURE OF OFFSETTING FINANCIAL ASSETS AND FINANCIAL LIABILITIES

Effective January 1, 2013, the Company complied with the amended disclosure requirements, regarding offsetting financial assets and financial liabilities, found in IFRS 7, "*Financial Instruments: Disclosures*" issued in December 2011. The additional disclosures can be found in Note 32. The application of the amendment had no impact on the Consolidated Statements of Earnings and Comprehensive Income or the Consolidated Balance Sheets.

DISCLOSURES OF RECOVERABLE AMOUNTS OF NON-FINANCIAL ASSETS

In May 2013, the IASB issued an amendment to IAS 36, "*Impairment of Assets*". The amendment removes certain disclosures of the recoverable amount of a CGU. The amendment is effective retrospectively for annual periods beginning on or after January 1, 2014. As allowed by the standard, the Company early adopted the amendment in the current period. Refer to Note 20 for the amended disclosures.

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 recognized 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 recognized 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 costs, 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 and 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 recognized 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.

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 have a significant impact on 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 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 costs. Recoverable amounts for the Company's refining assets utilizes assumptions such as refinery throughput, future commodity prices, operating costs, 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.

At December 31, 2013, 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 reserves as estimated by Cenovus's independent qualified reserves evaluators, crude oil and natural gas prices and the discount rate.

CRUDE OIL AND NATURAL GAS PRICES

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

	2014	2015	2016	2017	2018	*Average Annual % Change to 2024*
WTI (US$/barrel)	95.00	95.00	95.00	95.00	95.30	1.9%
AECO ($/Mcf)	4.00	4.25	4.55	4.75	5.00	2.4%

DISCOUNT RATE

Evaluations of discounted future cash flows are initiated using the discount rate of 10 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 the economic conditions could significantly change the estimated recoverable amount.

Decommissioning Costs

Provisions are recognized 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 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 recognized 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,	**2013**	2012	2011
Interest Expense – Short-Term Borrowings and Long-Term Debt	**271**	230	213
Premium on Redemption of Long-Term Debt (Note 22)	**33**	–	–
Interest Expense – Partnership Contribution Payable (Note 13)	**98**	118	138
Unwinding of Discount on Decommissioning Liabilities (Note 23)	**97**	86	75
Other	**30**	21	21
	529	455	447

7. INTEREST INCOME

For the years ended December 31,	**2013**	2012	2011
Interest Income – Partnership Contribution Receivable (Note 13)	**(82)**	(102)	(120)
Other	**(14)**	(7)	(4)
	(96)	(109)	(124)

8. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2013**	2012	2011
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued from Canada	**357**	(69)	78
U.S. Dollar Partnership Contribution Receivable Issued from Canada	**(305)**	(15)	(107)
Other	**(12)**	14	(13)
Unrealized Foreign Exchange (Gain) Loss	**40**	(70)	(42)
Realized Foreign Exchange (Gain) Loss	**168**	50	68
	208	(20)	26

9. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	**2013**	2012	2011
Current Tax			
Canada	**143**	188	150
United States [1]	**45**	121	4
Total Current Tax	**188**	309	154
Deferred Tax	**244**	474	575
	432	783	729

(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 recorded income taxes:

For the years ended December 31,	**2013**	2012	2011
Earnings Before Income Tax	**1,094**	1,778	2,207
Canadian Statutory Rate	**25.2%**	25.2%	26.7%
Expected Income Tax	**276**	448	589
Effect of Taxes Resulting from:			
Foreign Tax Rate Differential	**109**	146	82
Non-Deductible Stock-Based Compensation	**10**	10	18
Multi-Jurisdictional Financing	**(22)**	(27)	(50)
Foreign Exchange Gains (Losses) not Included in Net Earnings	**19**	14	(9)
Non-Taxable Capital (Gains) Losses	**31**	(7)	(8)
Derecognition (Recognition) of Capital Losses	**15**	(22)	26
Adjustments Arising from Prior Year Tax Filings	**(13)**	33	31
Withholding Tax on Foreign Dividend	**–**	68	–
Goodwill Impairment	**–**	99	–
Other	**7**	21	50
Total Tax	**432**	783	729
Effective Tax Rate	**39.5%**	44.0%	33.0%

The Canadian statutory tax rate remained unchanged at 25.2 percent for 2013. The Canadian statutory tax rate decreased to 25.2 percent in 2012 and 26.7 percent in 2011 as a result of tax legislation enacted in 2007. The U.S. statutory tax rate of 38.5 percent also remained unchanged for 2013. The U.S. statutory tax rate increased to 38.5 percent in 2012 from 37.5 percent in 2011 as a result of the allocation of taxable income to U.S. states.

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

As at	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Net Deferred Income Tax Liabilities			
Deferred Tax Liabilities to be Settled Within 12 Months	**75**	140	117
Deferred Tax Liabilities to be Settled After More Than 12 Months	**2,787**	2,420	1,976
	2,862	2,560	2,093

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 January 1, 2011	1,651	125	127	55	55	2,013
Charged/(Credited) to Earnings	725	38	(15)	16	75	839
Charged/(Credited) to OCI	–	–	–	–	–	–
Foreign Exchange Adjustments	18	–	–	–	2	20
As at January 1, 2012	2,394	163	112	71	132	2,872
Charged/(Credited) to Earnings	418	(104)	(85)	2	(32)	199
Charged/(Credited) to OCI	–	–	–	–	–	–
Foreign Exchange Adjustments	(17)	–	–	–	(1)	(18)
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	–	–	–	–	–	–
Foreign Exchange Adjustments	60	–	–	–	4	64
As at December 31, 2013	**3,000**	**88**	**–**	**2**	**152**	**3,242**

Deferred Income Tax Assets	***Unused Tax Losses***	***Risk Management***	***Other***	***Total***
As at January 1, 2011	(281)	(45)	(173)	(499)
Charged/(Credited) to Earnings	(270)	29	(21)	(262)
Charged/(Credited) to OCI	–	–	(5)	(5)
Foreign Exchange Adjustments	(13)	–	–	(13)
As at January 1, 2012	(564)	(16)	(199)	(779)
Charged/(Credited) to Earnings	244	11	20	275
Charged/(Credited) to OCI	–	–	–	–
Foreign Exchange Adjustments	11	–	–	11
As at December 31, 2012	(309)	(5)	(179)	(493)
Charged/(Credited) to Earnings	218	(30)	(69)	119
Charged/(Credited) to OCI	–	–	7	7
Foreign Exchange Adjustments	(13)	–	–	(13)
As at December 31, 2013	**(104)**	**(35)**	**(241)**	**(380)**

Net Deferred Income Tax Liabilities	***Total***
Net Deferred Income Tax Liabilities as at January 1, 2011	1,514
Charged/(Credited) to Earnings	577
Charged/(Credited) to OCI	(5)
Foreign Exchange Adjustments	7
Net Deferred Income Tax Liabilities as at January 1, 2012	2,093
Charged/(Credited) to Earnings	474
Charged/(Credited) to OCI	–
Foreign Exchange Adjustments	(7)
Net Deferred Income Tax Liabilities as at December 31, 2012	2,560
Charged/(Credited) to Earnings	244
Charged/(Credited) to OCI	7
Foreign Exchange Adjustments	51
Net Deferred Income Tax Liabilities as at December 31, 2013	**2,862**

The allocation of deferred income tax expense is composed of:

As at December 31,	**2013**	2012	2011
Credited/(Charged) to Net Deferred Income Tax Liabilities	**244**	474	577
Credited/(Charged) to Liabilities Related to Assets Held for Sale	**–**	–	(2)
Deferred Income Tax Expense	**244**	474	575

No tax liability has been recognized in respect of temporary differences associated with investments in subsidiaries. As no taxes are expected to be paid in respect of these differences related to Canadian subsidiaries, the amounts have not been determined. There are no taxable temporary differences associated with investments in non-Canadian subsidiaries.

The approximate amounts of tax pools available are:

As at December 31,	**2013**	2012
Canada	**5,425**	4,895
United States	**1,083**	1,607
	6,508	6,502

At December 31, 2013, the above tax pools included $5 million (2012 – $13 million; 2011 – $78 million) of Canadian non-capital losses and $238 million (2012 – $791 million; 2011 – $1,479 million) of U.S. federal net operating losses. These losses expire no earlier than 2029.

Also included in the December 31, 2013 tax pools are Canadian net capital losses totaling $561 million (2012 – $512 million; 2011 – $759 million), which are available for carry forward to reduce future capital gains. Of these losses, $561 million are unrecognized as a deferred income tax asset at December 31, 2013 (2012 – $406 million; 2011 – $286 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, *($ millions, except earnings per share)*	**2013**	2012	2011
Net Earnings – Basic and Diluted	**662**	995	1,478
Weighted Average Number of Shares – Basic	**755.9**	755.6	754.0
Dilutive Effect of Cenovus TSARs	**1.6**	2.9	3.7
Dilutive Effect of NSRs	**–**	–	–
Weighted Average Number of Shares – Diluted	**757.5**	758.5	757.7
Net Earnings Per Share – Basic	**$ 0.88**	$ 1.32	$ 1.96
Net Earnings Per Share – Diluted	**$ 0.87**	$ 1.31	$ 1.95

B) DIVIDENDS PER SHARE

The dividends paid in 2013 were $732 million or $0.968 per share, (2012 – $665 million, $0.88 per share; 2011 – $603 million, $0.80 per share). The Cenovus Board of Directors declared a first quarter 2014 dividend of $0.2662 per share, payable on March 31, 2014, to common shareholders of record as of March 14, 2014.

11. CASH AND CASH EQUIVALENTS

As at	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Cash	**363**	339	232
Short-Term Investments	**2,089**	821	263
	2,452	1,160	495

12. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at	**December 31, 2013**	*December 31, 2012*	*January 1, 2012*
Accruals	**1,589**	1,184	1,016
Partner Advances	**153**	87	191
Prepaids and Deposits	**55**	45	34
Joint Operations Receivables	**26**	30	30
Interest	**–**	23	28
Other	**51**	95	106
	1,874	1,464	1,405

13. PARTNERSHIP CONTRIBUTION RECEIVABLE AND PAYABLE

Cenovus has two significant joint operations, FCCL and WRB (Note 1). Through its interests in these joint operations, Cenovus's Consolidated Balance Sheets include a Partnership Contribution Receivable and Payable, which arose when Cenovus became a 50 percent partner of an integrated North American oil business. The integrated business consists of an upstream entity, FCCL, and a refining entity, WRB. On formation of the upstream entity Cenovus contributed assets, primarily Foster Creek and Christina Lake properties, with a fair value of US$7.5 billion and a note receivable of an equal amount was contributed by the partner ("Partnership Contribution Receivable"). For the refining entity, the partner contributed its Wood River and Borger refineries, located in Illinois and Texas, respectively, for a fair value of US$7.5 billion and Cenovus contributed a note payable of an equal amount ("Partnership Contribution Payable").

PARTNERSHIP CONTRIBUTION RECEIVABLE

On December 17, 2013, Cenovus, through its interest in FCCL, received US$1.4 billion, representing the remaining principal and interest due under the Partnership Contribution Receivable.

PARTNERSHIP CONTRIBUTION PAYABLE

This note payable is denominated in US dollars and bears interest at a rate of 6.0 percent per annum. Equal payments of principal and interest are payable quarterly, with final payment due January 2, 2017. The current and long-term Partnership Contribution Payable amounts recognized in the Consolidated Balance Sheets represent Cenovus's 50 percent share of this promissory note, net of payments to date.

Mandatory Payments – Partnership Contribution Payable

	2014	*2015*	*2016*	*2017*	*Thereafter*	***Total***
US$	412	438	464	120	–	**1,434**
C$ equivalent	438	465	494	128	–	**1,525**

14. INVENTORIES

As at	**December 31, 2013**	*December 31, 2012*	*January 1, 2012*
Product			
Refining and Marketing	**1,047**	1,056	1,079
Oil Sands	**156**	192	162
Conventional	**17**	11	25
Parts and Supplies	**39**	29	25
	1,259	1,288	1,291

During the year ended December 31, 2013, approximately $13,895 million of produced and purchased inventory was recognized as an expense (2012 – $12,363 million; 2011 – $11,568 million). Inventory costs include purchased product, the cost of condensate blended with heavy oil and related operating costs.

In the third quarter, Cenovus recorded a $28 million write-down of its product inventory as a result of a decline in refined product prices. Product turnover and the subsequent improvement in commodity prices have resulted in the $28 million being reversed in the fourth quarter.

15. ASSETS AND LIABILITIES HELD FOR SALE

As at	**December 31, 2013**	December 31, 2012	January 1, 2012
Assets Held for Sale			
Property, Plant and Equipment	–	–	116
Liabilities Related to Assets Held for Sale			
Decommissioning Liabilities	–	–	54
Deferred Income Taxes	–	–	–
	–	–	54

In the first quarter of 2013, Management decided to launch a public sales process to divest certain of its Bakken properties in Saskatchewan. The land base associated with these properties is relatively small and does not offer sufficient scalability to be material to Cenovus's overall asset portfolio. At that time, the assets were recorded at the lesser of fair value less costs of disposal and their carrying amount, and depletion ceased. These assets and the related liabilities are reported in the Conventional segment.

Management decided to discontinue the Bakken sales process until market conditions improve. While discussions with prospective purchasers have occurred, an offer that meets Management's expectations has not been received for the Bakken assets. As a result of this decision, as at December 31, 2013, the assets and associated decommissioning liabilities were reclassified from held for sale to PP&E and decommissioning liabilities, at their carrying amounts. Depletion, calculated on a per-unit of production basis, was recorded in the fourth quarter. The carrying value continues to be less than the estimated recoverable amount; therefore, no impairment was recognized.

16. EXPLORATION AND EVALUATION ASSETS

COST	
As at January 1, 2012	880
Additions [1]	687
Transfers to PP&E (Note 17)	(218)
Exploration Expense	(68)
Divestitures	(11)
Change in Decommissioning Liabilities	15
As at December 31, 2012	1,285
Additions	331
Transfers to PP&E (Note 17)	(95)
Exploration Expense	(50)
Divestitures	(17)
Change in Decommissioning Liabilities	19
As at December 31, 2013	**1,473**

(1) 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

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, 2013 include $60 million of internal costs directly related to the evaluation of these projects (year ended December 31, 2012 – $37 million; December 31, 2011 – $15 million). Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized during the year ended December 31, 2013 (year ended December 31, 2012 and 2011 – $nil).

For the year ended December 31, 2013, $95 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 (year ended December 31, 2012 – $218 million; December 31, 2011 – $356 million).

IMPAIRMENT

The impairment of E&E assets and any subsequent reversal of such impairment losses are recognized in exploration expense in the Consolidated Statements of Earnings and Comprehensive Income. For the year ended December 31, 2013, $50 million of previously capitalized E&E costs related to certain tight oil exploration assets within the Conventional segment were deemed not to be technically feasible and commercially viable and were recognized as exploration expense (2012 – $68 million; 2011 – $nil).

17. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	*Other Upstream*	*Refining Equipment*	*Other* (1)	*Total*
COST					
As at January 1, 2012	23,858	194	3,425	576	28,053
Additions	2,442	44	118	191	2,795
Transfers from E&E Assets (Note 16)	218	–	–	–	218
Transfers and Reclassifications	–	–	(55)	–	(55)
Change in Decommissioning Liabilities	484	–	(16)	–	468
Exchange Rate Movements	1	–	(73)	–	(72)
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 16)	95	–	–	–	95
Transfers and Reclassifications	(450)	–	(88)	–	(538)
Change in Decommissioning Liabilities	40	–	(1)	–	39
Exchange Rate Movements	–	–	238	–	238
As at December 31, 2013	**29,390**	**286**	**3,654**	**849**	**34,179**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at January 1, 2012	13,021	139	225	344	13,729
Depreciation, Depletion and Amortization	1,368	19	146	52	1,585
Transfers and Reclassifications	–	–	(55)	–	(55)
Impairment Losses	–	–	–	–	–
Exchange Rate Movements	1	–	(5)	–	(4)
As at December 31, 2012	14,390	158	311	396	15,255
Depreciation, Depletion and Amortization	1,522	35	138	79	1,774
Transfers and Reclassifications	(123)	–	(88)	–	(211)
Impairment Losses	2	–	–	–	2
Exchange Rate Movements	–	–	25	–	25
As at December 31, 2013	**15,791**	**193**	**386**	**475**	**16,845**
CARRYING VALUE					
As at January 1, 2012	10,837	55	3,200	232	14,324
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**

(1) Includes office furniture, fixtures, leasehold improvements, information technology and aircraft.

Additions to development and production assets include internal costs directly related to the development and construction of crude oil and natural gas properties of $204 million (2012 – $161 million; 2011 – $125 million). All of the Company's development and production assets are located within Canada. Costs classified as general and administrative expenses have not been capitalized as part of capital expenditures. No borrowing costs have been capitalized in 2013 (2012 and 2011 – $nil).

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

As at	**December 31, 2013**	*December 31, 2012*	*January 1, 2012*
Development and Production	**225**	71	–
Refining Equipment	**97**	13	125
Other	**–**	–	112
	322	84	237

IMPAIRMENT

The impairment of PP&E and any subsequent reversal of such impairment losses are recognized 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,	**2013**	2012	2011
Development and Production	**2**	–	2
Refining Equipment	**–**	–	45
	2	–	47

There were no impairment reversals of PP&E in 2013. The impairment losses for the year ended December 31, 2011 were related to a catalytic cracking unit at the Wood River Refinery, which will not be used in future operations, and an impairment on non-core natural gas assets that were reclassified as held for sale.

18. DIVESTITURES

In July 2013, the Company completed the sale of the Lower Shaunavon asset to an unrelated third party for proceeds of approximately $240 million plus closing adjustments. In the second quarter of 2013, an impairment loss of $57 million was recorded as additional DD&A on the transaction. A loss of $2 million was recorded on the sale in the third quarter. Other divestitures in 2013 include 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.

In January 2012, the Company completed the sale of non-core natural gas assets located in northern Alberta. A loss of $2 million was recorded on the sale. These assets and the related liabilities were reported in the Conventional segment.

In 2011, the Company disposed of non-core crude oil and natural gas properties and marine terminal facilities recognizing an after-tax gain of $91 million in the Consolidated Statement of Earnings and Comprehensive Income.

19. OTHER ASSETS

As at	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Equity Investments	**32**	14	6
Long-Term Receivables	**11**	22	18
Prepaids	**7**	8	8
Other	**18**	14	12
	68	58	44

20. GOODWILL

As at December 31,	**2013**	2012
Carrying Value, Beginning of Year	**739**	1,132
Impairment	**–**	(393)
Carrying Value, End of Year	**739**	739

There were no additions to goodwill during 2013 or 2012.

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 was:

As at	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Primrose (Foster Creek)	**242**	242	242
Northern Alberta	**497**	497	497
Suffield	**–**	–	393
	739	739	1,132

At December 31, 2012, the Company determined that the carrying amount of the Suffield CGU exceeded its fair value less costs of disposal and the full amount of the impairment was attributed to goodwill. An impairment loss of $393 million was recorded as goodwill impairment on the Consolidated Statement of Earnings and Comprehensive Income. The Suffield property resides on the Canadian Forces Base in southeast Alberta and the operating results are included in the Conventional segment. Future cash flows for the area declined due to lower natural gas and crude oil prices and increased operating costs. In addition, minimal levels of capital spending for natural gas resulted in production exceeding reserves replacement in the area. With lower future cash flows and decreasing volumes, the carrying amount of the Suffield CGU exceeded its fair value.

The recoverable amount was determined using fair value less costs of disposal. A calculation based on discounted after-tax cash flows of proved and probable reserves using forecast prices and costs as estimated by Cenovus's independent qualified reserves evaluators was completed. To assess reasonableness, an evaluation of fair value based on comparable asset transactions was also completed. As at December 31, 2012, the recoverable amount of the Suffield CGU was $1,130 million.

There were no impairments of goodwill in 2013 and 2011.

21. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Accruals	**2,317**	2,053	1,855
Partner Advances	**233**	87	191
Trade	**102**	133	148
Employee Long-Term Incentives	**116**	196	209
Interest	**82**	82	72
Other	**87**	99	104
	2,937	2,650	2,579

22. LONG-TERM DEBT

As at		***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Revolving Term Debt [1]	A	**–**	–	–
U.S. Dollar Denominated Unsecured Notes	B	**5,052**	4,726	3,559
Total Debt Principal	C	**5,052**	4,726	3,559
Debt Discounts and Transaction Costs	D	**(55)**	(47)	(32)
		4,997	4,679	3,527

(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, 2013 was 5.2 percent (2012 – 5.3 percent; 2011 – 5.5 percent).

A) REVOLVING TERM DEBT

At December 31, 2013, 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 September 2013 to extend the maturity date to November 30, 2017. 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. At December 31, 2013, there were no amounts drawn on Cenovus's committed bank credit facility (December 31, 2012 – $nil; January 1, 2012 – $nil).

B) UNSECURED NOTES

Unsecured notes are composed of:

As at	*US$ Principal Amount*	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
4.50% due September 15, 2014	800	**–**	796	814
5.70% due October 15, 2019	1,300	**1,382**	1,293	1,322
3.00% due August 15, 2022	500	**532**	498	–
3.80% due September 15, 2023	450	**479**	–	–
6.75% due November 15, 2039	1,400	**1,489**	1,393	1,423
4.45% due September 15, 2042	750	**798**	746	–
5.20% due September 15, 2043	350	**372**	–	–
		5,052	4,726	3,559

Cenovus has in place a Canadian base shelf prospectus for unsecured medium-term notes in the amount of $1.5 billion. The Canadian shelf prospectus allows for the issuance of medium-term notes in Canadian dollars or other foreign currencies, from time to time, in one or more offerings. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2013, no medium-term notes have been issued under this Canadian shelf prospectus. The Canadian shelf prospectus expires in June 2014.

On May 9, 2013, Cenovus amended its U.S. base shelf prospectus for unsecured notes to increase the total capacity from US$2.0 billion to US$3.25 billion. The U.S. shelf prospectus allows for the issuance of debt securities in U.S. dollars or other foreign currencies, from time to time, in one or more offerings. The terms of the notes, including, but not limited to, the principal amount, interest at either fixed or floating rates and maturity dates, will be determined at the date of issue. As at December 31, 2013, US$1.2 billion remains under this U.S. base shelf prospectus. The U.S. shelf prospectus expires in July 2014.

On August 15, 2013, Cenovus completed a public offering in the U.S. of senior unsecured notes of US$450 million, with a coupon rate of 3.80 percent, due September 15, 2023 and US$350 million of senior unsecured notes with a coupon rate of 5.20 percent, due September 15, 2043, for an aggregate principal amount of US$800 million. The net proceeds from the offering were used to partially fund the early redemption of Cenovus's US$800 million senior unsecured notes due September 15, 2014. A premium of US$32 million was paid on the early redemption of these notes and was recorded as finance costs.

As at December 31, 2013, 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***
2014	–	–	**–**
2015	–	–	**–**
2016	–	–	**–**
2017	–	–	**–**
2018	–	–	**–**
Thereafter	4,750	–	**5,052**
	4,750	–	**5,052**

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 2013, additional transaction costs of $15 million were recorded (2012 – $19 million).

23. 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,	**2013**	2012
Decommissioning Liabilities, Beginning of Year	**2,315**	1,777
Liabilities Incurred	**45**	99
Liabilities Settled	**(76)**	(66)
Transfers and Reclassifications	**(26)**	3
Change in Estimated Future Cash Flows	**414**	144
Change in Discount Rate	**(401)**	273
Unwinding of Discount on Decommissioning Liabilities	**97**	86
Foreign Currency Translation	**2**	(1)
Decommissioning Liabilities, End of Year	**2,370**	2,315

The undiscounted amount of estimated future cash flows required to settle the obligation is $7,471 million (December 31, 2012 – $6,865 million; January 1, 2012 – $6,541 million), which has been discounted using a credit-adjusted risk-free rate of 5.2 percent (December 31, 2012 – 4.2 percent; January 1, 2012 – 4.8 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. 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:

	2013		2012	
As at December 31,	***Credit-Adjusted Risk-Free Rate***	***Inflation Rate***	*Credit-Adjusted Risk-Free Rate*	*Inflation Rate*
One Percent Increase	**(345)**	**472**	(408)	572
One Percent Decrease	**461**	**(357)**	565	(418)

24. OTHER LIABILITIES

As at	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Deferred Revenues	**25**	31	35
Employee Long-Term Incentives	**67**	64	55
Pension and OPEB (Note 25)	**51**	60	46
Other	**37**	28	22
	180	183	158

25. 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 June 30, 2012 and the next required actuarial valuation will be as at December 31, 2014.

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,	**2013**	2012	**2013**	2012
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**134**	84	**20**	19
Current Service Costs	**17**	10	**2**	2
Interest Costs (1)	**6**	4	**1**	1
Benefits Paid	**(5)**	(2)	**–**	–
Plan Participant Contributions	**2**	1	**–**	–
Plan Conversion	**–**	30	**–**	–
Remeasurements:				
(Gains) Losses from Experience Adjustments	**1**	3	**–**	1
(Gains) Losses from Changes in Demographic Assumptions	**12**	–	**(1)**	(1)
(Gains) Losses from Changes in Financial Assumptions	**(19)**	4	**(4)**	(2)
Defined Benefit Obligation, End of Year	**148**	134	**18**	20
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**94**	57	**–**	–
Employer Contributions	**15**	22	**–**	–
Plan Participant Contributions	**2**	1	**–**	–
Benefits Paid	**(5)**	(2)	**–**	–
Interest Income (1)	**2**	3	**–**	–
Asset Transfer From Plan Conversion	**–**	12	**–**	–
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	**7**	1	**–**	–
Fair Value of Plan Assets, End of Year	**115**	94	**–**	–
Pension and Other Post-Employment Benefit (Liability) (2)	**(33)**	(40)	**(18)**	(20)

(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 16 years and 12 years, respectively.

B) PENSION AND OPEB COSTS

Pension and OPEB costs are:

	Pension Benefits			OPEB		
For the years ended December 31,	**2013**	2012	2011	**2013**	2012	2011
Defined Benefit Plan Cost:						
Current Service Costs	**17**	10	3	**2**	2	2
Past Service Costs (1)	**–**	18	–	**–**	–	–
Net Interest Costs	**4**	1	1	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**(7)**	(1)	4	**–**	–	–
(Gains) Losses from Experience Adjustments	**1**	3	(1)	**–**	1	–
(Gains) Losses from Changes in Demographic Assumptions	**12**	–	–	**(1)**	(1)	–
(Gains) Losses from Changes in Financial Assumptions	**(19)**	4	12	**(4)**	(2)	2
Defined Benefit Plan Cost (Gain)	**8**	35	19	**(2)**	1	5
Defined Contribution Plan Cost	**27**	25	22	**–**	–	–
Total Plan Cost	**35**	60	41	**(2)**	1	5

(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 65 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, 2013**	December 31, 2012	January 1, 2012
Equity Securities			
Equity Funds and Balanced Funds	**67**	52	30
Other	**8**	3	–
Bond Funds	**25**	24	17
Non-Invested Assets	**12**	11	7
Real Estate	**3**	4	3
	115	94	57

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 June 30, 2012, 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, 2014 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,	**2013**	2012	2011	**2013**	2012	2011
Discount Rate	**4.75%**	4.00%	4.25%	**4.75%**	4.00%	4.25%
Future Salary Growth Rate	**4.39%**	4.39%	3.99%	**5.65%**	5.77%	5.77%
Average Longevity (Years)	**88.5**	86.1	86.1	**88.5**	86.1	86.1
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**7.00%**	8.00%	10.00%

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 at December 31, 2013 is shown below.

	One Percentage Point Increase	*One Percentage Point Decrease*
Discount Rate	**(23)**	**29**
Future Salary Growth Rate	**4**	**(4)**
Health Care Cost Trend Rate	**1**	**(1)**
Future Mortality Rate (Years)	**3**	**(3)**

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 recognized 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.

26. SHARE CAPITAL

A) AUTHORIZED

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. 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

	2013		2012	
As at December 31,	***Number of Common Shares*** *(thousands)*	***Amount***	*Number of Common Shares (thousands)*	*Amount*
Outstanding, Beginning of Year	**755,843**	**3,829**	754,499	3,780
Common Shares Issued under Stock Option Plans	**970**	**31**	1,344	49
Common Shares Cancelled	**(767)**	**(3)**	–	–
Outstanding, End of Year	**756,046**	**3,857**	755,843	3,829

During the year ended December 31, 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 was formed. Due to the Arrangement, 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, 2013 (2012 – nil).

As at December 31, 2013, there were 24 million (2012 – 28 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 28A.

	Pre-Arrangement Earnings	*Stock-Based Compensation*	*Total*
As at January 1, 2012	4,083	24	4,107
Stock-Based Compensation Expense	–	47	47
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**

27. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	*Foreign Currency Translation*	*Available for Sale Investments*	*Total*
As at January 1, 2012	(22)	119	–	97
Other Comprehensive Income (Loss), Before Tax	(4)	(24)	–	(28)
Income Tax	–	–	–	–
As at December 31, 2012	(26)	95	–	69
Other Comprehensive Income (Loss), Before Tax	18	117	13	148
Income Tax	(4)	–	(3)	(7)
As at December 31, 2013	**(12)**	**212**	**10**	**210**

28. 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.

In accordance with the Arrangement described in Note 1, each Cenovus and Encana employee exchanged their original Encana TSAR for one Cenovus replacement TSAR and one Encana replacement TSAR. The terms and conditions of the Cenovus and Encana replacement TSARs are similar to the terms and conditions of the original Encana TSAR. The original exercise price of the Encana TSAR was apportioned to the Cenovus and Encana replacement TSARs based on the one day volume weighted average trading price of Cenovus's common share price relative to that of Encana's common share price on the TSX on December 2, 2009. Cenovus TSARs and Cenovus replacement TSARs are measured against the Cenovus common share price while Encana replacement TSARs are measured against the Encana common share price. The Cenovus replacement TSARs have similar vesting provisions as outlined above for the Employee Stock Option Plan. The original Encana performance TSARs were also exchanged under the same terms as the original Encana TSARs.

As at December 31, 2013	***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**	**5.46**	**35.26**	**30.40**	**26,315**
TSARs	Prior to February 17, 2010	**5**	**0.15**	**26.28**	**30.40**	**2,483**
TSARs	On or After February 17, 2010	**7**	**3.20**	**26.71**	**30.40**	**4,603**
Encana Replacement TSARs held by Cenovus Employees	Prior to December 1, 2009	**5**	**0.12**	**29.06**	**19.18**	**3,904**
Cenovus Replacement TSARs held by Encana Employees	Prior to December 1, 2009	**5**	**0.12**	**26.28**	**30.40**	**1,479**

Unless otherwise indicated, all references to TSARs collectively refer to both the Cenovus issued TSARs and Cenovus replacement TSARs.

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2013 was $6.10 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	**1.49%**
Expected Dividend Yield	**2.65%**
Expected Volatility [(1)]	**27.62%**
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, 2013:

As at December 31, 2013	***Number of NSRs*** *(thousands)*	***Weighted Average Exercise Price*** *($)*
Outstanding, Beginning of Year	**15,074**	**37.52**
Granted	**12,078**	**32.50**
Exercised for Common Shares	**–**	**31.85**
Forfeited	**(837)**	**36.26**
Outstanding, End of Year	**26,315**	**35.26**
Exercisable, End of Year	**5,966**	**37.37**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $33.11.

As at December 31, 2013 Range of Exercise Price ($)	Outstanding NSRs Number of NSRs (thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
25.00 to 29.99	**271**	**6.49**	**29.64**
30.00 to 34.99	**13,407**	**6.07**	**32.61**
35.00 to 39.99	**12,637**	**4.78**	**38.18**
	26,315	**5.46**	**35.26**

As at December 31, 2013 Range of Exercise Price ($)	Exercisable NSRs Number of NSRs (thousands)	Weighted Average Exercise Price ($)
30.00 to 34.99	**726**	**32.92**
35.00 to 39.99	**5,240**	**37.99**
	5,966	**37.37**

TSARs Held by Cenovus Employees

The Company has recorded a liability of $33 million at December 31, 2013 (December 31, 2012 – $64 million; January 1, 2012 – $90 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	**1.91%**
Expected Dividend Yield	**3.05%**
Expected Volatility [1]	**26.43%**
Cenovus's Common Share Price	**$ 30.40**

(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 at December 31, 2013 was $27 million (2012 – $45 million).

The following tables summarize information related to the TSARs held by Cenovus employees as at December 31, 2013:

As at December 31, 2013	Number of TSARs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**11,251**	**28.13**
Exercised for Cash Payment	**(1,840)**	**29.70**
Exercised as Options for Common Shares	**(955)**	**29.07**
Forfeited	**(67)**	**28.62**
Expired	**(1,303)**	**33.77**
Outstanding, End of Year	**7,086**	**26.56**
Exercisable, End of Year	**7,037**	**26.51**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $32.60.

As at December 31, 2013 Range of Exercise Price ($)	Outstanding TSARs Number of TSARs (thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)
20.00 to 29.99	**6,910**	**2.08**	**26.40**
30.00 to 39.99	**176**	**3.90**	**32.71**
	7,086	**2.13**	**26.56**

As at December 31, 2013 Range of Exercise Price ($)	Exercisable TSARs Number of TSARs (thousands)	 Weighted Average Exercise Price ($)
20.00 to 29.99	**6,910**	**26.40**
30.00 to 39.99	**127**	**32.42**
	7,037	**26.51**

The closing price of Cenovus's common shares on the TSX as at December 31, 2013 was $30.40.

Encana Replacement TSARs Held by Cenovus Employees

Cenovus is required to reimburse Encana for cash payments made by Encana to Cenovus employees when a Cenovus employee exercises an Encana replacement TSAR for cash. No further Encana Replacement TSARs will be granted to Cenovus employees.

The Company has recorded a liability of $nil at December 31, 2013 (December 31, 2012 – $1 million; January 1, 2012 – $1 million) in the Consolidated Balance Sheets based on the fair value of each Encana replacement 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	**1.91%**
Expected Dividend Yield	**3.63%**
Expected Volatility [1]	**30.27%**
Encana's Common Share Price	**$ 19.18**

(1) Expected volatility has been based on the historical volatility of Encana's publicly traded shares.

The intrinsic value of vested Encana replacement TSARs held by Cenovus employees at December 31, 2013 was $nil (2012 – $nil).

The following tables summarize information related to the Encana replacement TSARs held by Cenovus employees as at December 31, 2013:

As at December 31, 2013	Number of TSARs (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	**7,722**	**32.66**
Forfeited	**(187)**	**30.07**
Expired	**(3,631)**	**36.66**
Outstanding, End of Year	**3,904**	**29.06**
Exercisable, End of Year	**3,904**	**29.06**

As at December 31, 2013 Range of Exercise Price ($)	Outstanding & Exercisable TSARs Number of TSARs (thousands)	 Weighted Average Remaining Contractual Life (Years)	 Weighted Average Exercise Price ($)
20.00 to 29.99	**3,874**	**0.12**	**29.04**
30.00 to 39.99	**30**	**0.73**	**31.53**
	3,904	**0.12**	**29.06**

The closing price of Encana common shares on the TSX as at December 31, 2013 was $19.18.

Cenovus Replacement TSARs Held by Encana Employees

Encana is required to reimburse Cenovus for cash payments made by Cenovus to Encana employees when these employees exercise a Cenovus replacement TSAR for cash. No compensation expense is recognized and no further Cenovus replacement TSARs will be granted to Encana employees.

The Company has recorded a liability of $6 million at December 31, 2013 (December 31, 2012 – $35 million; January 1, 2012 – $83 million) in the Consolidated Balance Sheets based on the fair value of each Cenovus replacement TSAR held by Encana employees, with an offsetting account receivable from Encana. 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	**1.91%**
Expected Dividend Yield	**3.05%**
Expected Volatility [1]	**26.43%**
Cenovus's Common Share Price	**$ 30.40**

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

The intrinsic value of vested Cenovus replacement TSARs held by Encana employees at December 31, 2013 was $6 million (2012 – $22 million).

The following tables summarize the information related to the Cenovus replacement TSARs held by Encana employees as at December 31, 2013:

As at December 31, 2013	***Number of TSARs*** *(thousands)*	***Weighted Average Exercise Price*** *($)*
Outstanding, Beginning of Year	**5,229**	**29.29**
Exercised for Cash Payment	**(2,351)**	**28.75**
Exercised as Options for Common Shares	**(15)**	**29.54**
Forfeited	**(27)**	**28.74**
Expired	**(1,357)**	**33.51**
Outstanding, End of Year	**1,479**	**26.28**
Exercisable, End of Year	**1,479**	**26.28**

For options exercised during the year, the weighted average market price of Cenovus's common shares at the date of exercise was $32.42.

	Outstanding & Exercisable TSARs		
As at December 31, 2013 *Range of Exercise Price ($)*	***Number of TSARs*** *(thousands)*	***Weighted Average Remaining Contractual Life*** *(Years)*	***Weighted Average Exercise Price*** *($)*
20.00 to 29.99	**1,479**	**0.12**	**26.28**

The closing price of Cenovus's common shares on the TSX as at December 31, 2013 was $30.40.

B) PSUs

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 $103 million at December 31, 2013 (December 31, 2012 – $124 million; January 1, 2012 – $55 million) in the Consolidated Balance Sheets for PSUs based on the market value of the Cenovus common shares at December 31, 2013. The intrinsic value of vested PSUs was $nil at December 31, 2013 and 2012 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, 2013	***PSUs*** *(thousands)*
Outstanding, Beginning of Year	**5,258**
Granted	**2,552**
Vested and Paid Out	**(2,008)**
Cancelled	**(194)**
Units in Lieu of Dividends	**177**
Outstanding, End of Year	**5,785**

C) DSUs

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 $36 million at December 31, 2013 (December 31, 2012 – $36 million; January 1, 2012 – $35 million) in the Consolidated Balance Sheets for DSUs based on the market value of the Cenovus common shares at December 31, 2013. 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, 2013	**DSUs** *(thousands)*
Outstanding, Beginning of Year	**1,084**
Granted to Directors	**65**
Granted from Annual Bonus Awards	**8**
Units in Lieu of Dividends	**36**
Redeemed	**(1)**
Outstanding, End of Year	**1,192**

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,	**2013**	2012	2011
NSRs	**35**	27	16
TSARs Held by Cenovus Employees	**(16)**	(1)	24
Encana Replacement TSARs Held by Cenovus Employees	**–**	–	(8)
PSUs	**32**	46	27
DSUs	**–**	3	4
Total Stock-Based Compensation Expense (Recovery)	**51**	75	63

29. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2013**	2012	2011
Salaries, Bonuses and Other Short-Term Employee Benefits	**494**	441	399
Defined Contribution Pension Plan	**17**	14	13
Defined Benefit Pension Plan and OPEB	**15**	20	4
Stock-Based Compensation (Note 28)	**51**	75	63
	577	550	479

30. 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,	**2013**	2012	2011
Salaries, Director Fees and Short-Term Benefits	**31**	27	25
Post-Employment Benefits	**4**	7	3
Other Long-Term Benefits	**–**	–	–
Stock-Based Compensation	**24**	35	35
	59	69	63

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

31. 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 or Receivable. 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, 2013***	*December 31, 2012*	*January 1, 2012*
Long-Term Debt	**4,997**	4,679	3,527
Shareholders' Equity	**9,946**	9,782	9,384
Capitalization	**14,943**	14,461	12,911
Debt to Capitalization	**33%**	32%	27%

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

As at December 31,	**2013**	2012	2011
Debt	**4,997**	4,679	3,527
Net Earnings	**662**	995	1,478
Add (Deduct):			
Finance Costs	**529**	455	447
Interest Income	**(96)**	(109)	(124)
Income Tax Expense	**432**	783	729
Depreciation, Depletion and Amortization	**1,833**	1,585	1,295
Goodwill Impairment	**–**	393	–
E&E Impairment	**50**	68	–
Unrealized (Gain) Loss on Risk Management	**415**	(57)	(180)
Foreign Exchange (Gain) Loss, Net	**208**	(20)	26
(Gain) Loss on Divestiture of Assets	**1**	–	(107)
Other (Income) Loss, Net	**2**	(5)	4
Adjusted EBITDA	**4,036**	4,088	3,568
Debt to Adjusted EBITDA	**1.2x**	1.1x	1.0x

It is Cenovus's intention to maintain investment grade credit ratings to help ensure it has continuous access to capital and the financial flexibility to fund its capital programs, meet its financial obligations and finance potential acquisitions. 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.

At December 31, 2013, Cenovus is in compliance with all of the terms of its debt agreements.

32. 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 Receivable and Payable, partner loans, 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 Receivable and Payable, partner loans 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, 2013, the carrying value of Cenovus's long-term debt was $4,997 million and the fair value was $5,388 million (December 31, 2012 carrying value – $4,679 million, fair value – $5,582 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. A reconciliation of changes in the fair value of available for sale financial assets is below.

As at December 31,	**2013**	2012
Fair Value, Beginning of Year	**14**	6
Acquisition of Investments	**5**	8
Change in Fair Value (1)	**13**	–
Fair Value, End of Year	**32**	14

(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 at December 31, 2013 range from $44.75 to $66.00 per megawatt hour.

Summary of Unrealized Risk Management Positions

	December 31, 2013			*December 31, 2012*			*January 1, 2012*		
	Risk Management			*Risk Management*			*Risk Management*		
As at	***Asset***	***Liability***	***Net***	*Asset*	*Liability*	*Net*	*Asset*	*Liability*	*Net*
Commodity Prices									
Crude Oil	**10**	**136**	**(126)**	221	16	205	22	65	(43)
Natural Gas	**–**	**–**	**–**	66	1	65	247	3	244
Power	**–**	**3**	**(3)**	1	1	–	15	–	15
Total Fair Value	**10**	**139**	**(129)**	288	18	270	284	68	216

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

As at	***December 31, 2013***	*December 31, 2012*	*January 1, 2012*
Prices Sourced from Observable Data or Market Corroboration (Level 2)	**(126)**	270	216
Prices Determined from Unobservable Inputs (Level 3)	**(3)**	–	–
	(129)	270	216

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 our risk management assets and liabilities:

	2013	2012
Fair Value of Contracts, Beginning of Year	**270**	216
Fair Value of Contracts Realized During the Year	**(122)**	(336)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered into During the Year	**(293)**	393
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**16**	(3)
Fair Value of Contracts, End of Year	**(129)**	270

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:

	December 31, 2013			December 31, 2012		
	Risk Management			Risk Management		
As at	**Asset**	**Liability**	**Net**	*Asset*	*Liability*	*Net*
Recognized Risk Management Positions						
Gross Amount	**16**	**145**	**(129)**	306	36	270
Amount Offset	**(6)**	**(6)**	**–**	(18)	(18)	–
Net Amount per Consolidated Financial Statements	**10**	**139**	**(129)**	288	18	270

	January 1, 2012		
	Risk Management		
As at	*Asset*	*Liability*	*Net*
Recognized Risk Management Positions			
Gross Amount	307	91	216
Amount Offset	(23)	(23)	–
Net Amount per Consolidated Financial Statements	284	68	216

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, 2013, $10 million (December 31, 2012 – $12 million; January 1, 2012 – $12 million) was pledged as collateral, of which $5 million (December 31, 2012 – $12 million; January 1, 2012 – $4 million) could have been withdrawn.

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

For the years ended December 31,	**2013**	2012	2011
Realized (Gain) Loss [1]	**(122)**	(336)	(68)
Unrealized (Gain) Loss [2]	**415**	(57)	(180)
(Gain) Loss on Risk Management	**293**	(393)	(248)

(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.

33. 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 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 NYMEX price. To help protect against widening natural gas price differentials in various production areas, Cenovus has entered into a limited number of swaps to manage the price differentials between these 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 at December 31, 2013

As at December 31, 2013	*Notional Volumes*	*Term*	*Average Price*	*Fair Value*
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	30,000 bbls/d	2014	US$102.04/bbl	**(73)**
Brent Fixed Price	20,000 bbls/d	2014	$107.06/bbl	**(64)**
WCS Differential [1]	15,900 bbls/d	2014	US$(20.39)/bbl	**10**
Other Financial Positions [2]				**1**
Crude Oil Fair Value Position				**(126)**
Power Purchase Contracts				
Power Fair Value Position				**(3)**

(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 as at December 31 could have resulted in unrealized gains (losses) impacting earnings before income tax for the year ended December 31 as follows:

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	± $1 per mcf Applied to NYMEX Natural Gas Hedges	**–**	**–**
Natural Gas Basis Price	± $0.10 per mcf Applied to Natural Gas Basis Hedges	**–**	**–**
Power Commodity Price	± $25 per MWHr Applied to Power Hedge	**19**	**(19)**

RISK MANAGEMENT POSITIONS IN PLACE AS AT DECEMBER 31, 2012

Commodity	*Sensitivity Range*	*Increase*	*Decrease*
Crude Oil Commodity Price	± US$10 per bbl Applied to Brent, WTI and Condensate Hedges	(156)	156
Crude Oil Differential Price	± US$5 per bbl Applied to Differential Hedges tied to Production	111	(111)
Natural Gas Commodity Price	± $1 per mcf Applied to NYMEX and AECO Hedges	(55)	55
Natural Gas Basis Price	± $0.10 per mcf Applied to Natural Gas Basis Hedges	1	(1)
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 dollars 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. At December 31, 2013, Cenovus had US$4,750 million in U.S. dollar debt issued from Canada (2012 – US$4,750 million; 2011 – US$3,500 million) and US$nil related to the U.S. dollar Partnership Contribution Receivable (2012 – US$1,791 million; 2011 – US$2,157 million). 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,	**2013**	2012	2011
$0.01 Increase in Foreign Exchange Rate	**48**	30	13
$0.01 Decrease in Foreign Exchange Rate	**(48)**	(30)	(13)

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.

At December 31, 2013, the increase or decrease in net earnings for a one percentage point change in interest rates on floating rate debt amounts to $nil (2012 – $nil; 2011 – $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 credit policies 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. At December 31, 2013 and 2012, substantially all of the Company's accounts receivable were current. As at December 31, 2013, 94 percent (2012 – 87 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.

At December 31, 2013, Cenovus had four counterparties (2012 – two counterparties) whose net settlement position individually account for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts by counterparty. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, Partnership Contribution Receivable, partner loans receivable, 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 31, 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. At December 31, 2013, Cenovus had $3.0 billion available on its committed credit facility. In addition, Cenovus had in place a Canadian debt shelf prospectus for $1.5 billion and unused capacity of US$1.2 billion under a U.S. debt shelf prospectus, the availability of which are dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

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**

2012	*Less than 1 Year*	*1–3 Years*	*4–5 Years*	*Thereafter*	*Total*
Accounts Payable and Accrued Liabilities	2,650	–	–	–	2,650
Risk Management Liabilities [1]	17	1	–	–	18
Long-Term Debt [2]	254	1,263	432	7,051	9,000
Partnership Contribution Payable [2]	486	972	609	–	2,067
Other [2]	–	9	4	4	17

(1) Risk management liabilities subject to master netting agreements.

(2) Principal and interest, including current portion.

34. SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2013**	2012	2011
Interest Paid	**409**	342	357
Interest Received	**119**	113	128
Income Taxes Paid	**133**	304	–

35. 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:

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**

2012	*1 Year*	*2 Years*	*3 Years*	*4 Years*	*5 Years*	*Thereafter*	*Total*
Pipeline Transportation [1]	145	209	378	403	675	8,130	9,940
Operating Leases (Building Leases)	109	106	112	110	104	1,602	2,143
Product Purchases	81	18	18	6	–	–	123
Capital Commitments	320	54	61	53	6	2	496
Other Long-Term Commitments	33	25	18	7	6	10	99
Total Payments [2]	688	412	587	579	791	9,744	12,801
Fixed Price Product Sales	50	52	54	55	3	–	214

(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.

At December 31, 2013, there were outstanding letters of credit aggregating $78 million issued as security for performance under certain contracts (2012 – $36 million).

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 33.

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 recognized a liability of $2,370 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

	2013					2012				
($ millions, except per share amounts)	*Year*	*Q4*	*Q3*	*Q2*	*Q1*	*Year*	*Q4*	*Q3*	*Q2*	*Q1*
Gross Sales										
Upstream	**6,892**	1,767	1,926	1,646	1,553	6,156	1,584	1,496	1,382	1,694
Refining and Marketing	**12,706**	3,223	3,459	3,078	2,946	11,356	2,336	3,066	2,962	2,992
Corporate and Eliminations	**(605)**	(163)	(190)	(130)	(122)	(283)	(118)	(100)	(65)	–
Less: Royalties	**336**	80	120	78	58	387	78	122	65	122
Revenues	**18,657**	4,747	5,075	4,516	4,319	16,842	3,724	4,340	4,214	4,564
OPERATING CASH FLOW										
Crude Oil and Natural Gas Liquids										
Foster Creek	**877**	204	252	232	189	924	246	227	223	228
Christina Lake	**596**	179	248	96	73	343	118	93	70	62
Pelican Lake	**385**	92	130	96	67	418	98	108	85	127
Other Conventional	**1,003**	232	285	251	235	962	240	227	228	267
Natural Gas	**437**	110	94	118	115	513	134	126	121	132
Other Upstream Operations	**27**	8	5	8	6	18	7	5	1	5
	3,325	825	1,014	801	685	3,178	843	786	728	821
Refining and Marketing	**1,143**	151	139	324	529	1,273	123	528	353	269
Operating Cash Flow (1)	**4,468**	976	1,153	1,125	1,214	4,451	966	1,314	1,081	1,090
CASH FLOW INFORMATION										
Cash from Operating Activities	**3,539**	976	840	828	895	3,420	758	1,029	968	665
Deduct (Add back):										
Net Change in Other Assets and Liabilities	**(120)**	(30)	(25)	(31)	(34)	(113)	(42)	(19)	(20)	(32)
Net Change in Non-Cash Working Capital	**50**	171	(67)	(12)	(42)	(110)	103	(69)	63	(207)
Cash Flow (2)	**3,609**	835	932	871	971	3,643	697	1,117	925	904
Per Share – Basic	**4.77**	1.10	1.23	1.15	1.28	4.82	0.92	1.48	1.22	1.20
– Diluted	**4.76**	1.10	1.23	1.15	1.28	4.80	0.92	1.47	1.22	1.19
Operating Earnings (3)	**1,171**	212	313	255	391	868	(188)	432	284	340
Per Share – Diluted	**1.55**	0.28	0.41	0.34	0.52	1.14	(0.25)	0.57	0.37	0.45
Net Earnings (Loss)	**662**	(58)	370	179	171	995	(117)	289	397	426
Per Share – Basic	**0.88**	(0.08)	0.49	0.24	0.23	1.32	(0.15)	0.38	0.53	0.56
– Diluted	**0.87**	(0.08)	0.49	0.24	0.23	1.31	(0.15)	0.38	0.52	0.56
Effective Tax Rates using										
Net Earnings	**39.5%**					44.0%				
Operating Earnings, excluding Divestitures	**31.4%**					47.0%				
Canadian Statutory Rate	**25.2%**					25.2%				
U.S. Statutory Rate	**38.5%**					38.5%				
Foreign Exchange Rates *(US$ per C$1)*										
Average	**0.971**	0.953	0.963	0.977	0.992	1.001	1.009	1.005	0.990	0.999
Period end	**0.940**	0.940	0.972	0.951	0.985	1.005	1.005	1.017	0.981	1.001

(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 defined as net earnings excluding after-tax gain (loss) on discontinuance, after-tax gain on bargain purchase, after-tax effect of unrealized risk management gains (losses) on derivative instruments, after-tax unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, after-tax foreign exchange gains (losses) on settlement of intercompany transactions, after-tax gains (losses) on divestiture of assets, deferred income tax on foreign exchange recognized for tax purposes only related to U.S. dollar intercompany debt, the effect of changes in statutory income tax rates and after-tax realized foreign exchange loss on early receipt of the Partnership Contribution Receivable.

FINANCIAL STATISTICS (continued)

FINANCIAL METRICS (NON-GAAP MEASURES)	2013					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Debt to Capitalization [4] [5]	**33%**	33%	32%	33%	33%	32%	32%	32%	27%	28%
Net Debt to Capitalization [4] [6]	**29%**	29%	28%	30%	28%	27%	27%	24%	25%	25%
Debt to Adjusted EBITDA [5] [7]	**1.2x**	1.2x	1.2x	1.2x	1.1x	1.1x	1.1x	1.1x	1.0x	1.0x
Net Debt to Adjusted EBITDA [6] [7]	**1.0x**	1.0x	1.0x	1.0x	0.9x	0.9x	0.9x	0.8x	0.9x	0.9x
Return on Capital Employed [8]	**6%**	6%	6%	5%	7%	9%	9%	11%	14%	16%
Return on Common Equity [9]	**7%**	7%	6%	5%	8%	10%	10%	14%	17%	21%

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

(5) 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.

(6) 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.

(7) We define trailing 12-month 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.

(8) 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.

(9) Return on common equity is calculated, on a trailing 12-month basis, as net earnings divided by average shareholders' equity.

COMMON SHARE INFORMATION	2013					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Common Shares Outstanding *(millions)*										
Period end	**756.0**	756.0	755.8	755.8	755.8	755.8	755.8	755.8	755.7	755.6
Average – Basic	**755.9**	755.9	755.8	755.8	756.0	755.6	755.8	755.7	755.7	755.1
Average – Diluted	**757.5**	757.2	757.2	757.1	758.4	758.5	758.3	758.0	757.9	759.5
Price Range *($ per share)*										
TSX – C$										
High	**34.13**	31.69	32.77	32.08	34.13	39.64	35.69	36.25	36.68	39.64
Low	**28.32**	29.33	28.98	28.32	31.09	30.09	31.82	30.37	30.09	33.24
Close	**30.40**	30.40	30.74	30.00	31.46	33.29	33.29	34.31	32.37	35.90
NYSE – US$										
High	**34.50**	30.34	31.60	31.58	34.50	39.81	36.11	37.31	37.26	39.81
Low	**27.25**	27.60	28.00	27.25	30.58	28.83	31.74	30.20	28.83	32.45
Close	**28.65**	28.65	29.85	28.52	30.99	33.54	33.54	34.85	31.80	35.94
Dividends Paid *($ per share)*	**$0.968**	$ 0.242	$ 0.242	$ 0.242	$ 0.242	$ 0.88	$ 0.22	$ 0.22	$ 0.22	$ 0.22
Share Volume Traded *(millions)*	**685.7**	146.2	183.0	201.6	154.9	664.3	141.7	152.6	192.6	177.4

NET CAPITAL INVESTMENT	2013					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Capital Investment *($ millions)*										
Oil Sands										
Foster Creek	**797**	193	205	189	210	735	208	199	169	159
Christina Lake	**688**	189	162	162	175	593	168	147	140	138
Total	**1,485**	382	367	351	385	1,328	376	346	309	297
Other Oil Sands	**398**	120	60	69	149	365	82	42	41	200
	1,883	502	427	420	534	1,693	458	388	350	497
Conventional										
Pelican Lake	**465**	115	96	111	143	518	147	128	104	139
Other Conventional	**726**	216	178	134	198	848	257	231	129	231
	1,191	331	274	245	341	1,366	404	359	233	370
Refining and Marketing	**107**	37	19	26	25	118	58	38	24	(2)
Corporate	**81**	28	23	15	15	191	58	45	53	35
Capital Investment	**3,262**	898	743	706	915	3,368	978	830	660	900
Acquisitions [1]	**32**	27	1	1	3	114	70	8	28	8
Divestitures	**(283)**	(41)	(241)	–	(1)	(76)	(11)	–	1	(66)
Net Acquisition and Divestiture Activity	**(251)**	(14)	(240)	1	2	38	59	8	29	(58)
Net Capital Investment	**3,011**	884	503	707	917	3,406	1,037	838	689	842

(1) Q4 2012 asset acquisition included the assumption of a decommissioning liability of $33 million.

OPERATING STATISTICS – BEFORE ROYALTIES

UPSTREAM PRODUCTION VOLUMES	2013					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil and Natural Gas Liquids *(bbls/d)*										
Oil Sands – Heavy Oil										
Foster Creek	**53,190**	52,419	49,092	55,338	55,996	57,833	59,059	63,245	51,740	57,214
Christina Lake	**49,310**	61,471	52,732	38,459	44,351	31,903	41,808	32,380	28,577	24,733
Total	**102,500**	113,890	101,824	93,797	100,347	89,736	100,867	95,625	80,317	81,947
Conventional Liquids										
Pelican Lake	**24,254**	24,528	24,826	23,959	23,687	22,552	23,507	23,539	22,410	20,730
Other Heavy Oil	**15,991**	15,480	15,507	16,284	16,712	16,015	16,243	15,492	15,703	16,624
Light and Medium Oil	**35,467**	33,646	33,651	36,137	38,508	36,071	36,034	35,695	36,149	36,411
Natural Gas Liquids (2)	**1,063**	1,199	1,130	950	971	1,029	995	999	987	1,138
Total Crude Oil and Natural Gas Liquids	**179,275**	188,743	176,938	171,127	180,225	165,403	177,646	171,350	155,566	156,850
Natural Gas *(MMcf/d)*										
Oil Sands	**21**	21	23	22	18	30	27	24	31	39
Conventional	**508**	493	500	514	527	564	539	553	565	597
Total Natural Gas	**529**	514	523	536	545	594	566	577	596	636
Total Production *(BOE/d)*	**267,442**	274,410	264,105	260,460	271,058	264,403	271,979	267,517	254,899	262,850

(2) Natural gas liquids include condensate volumes.

AVERAGE ROYALTY RATES *(excluding impact of Realized Gain (Loss) on Risk Management)*	2013					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Oil Sands										
Foster Creek	**5.8%**	6.3%	7.6%	5.7%	2.9%	11.8%	8.0%	19.1%	4.6%	13.9%
Christina Lake	**6.8%**	7.8%	7.0%	5.6%	5.7%	6.2%	5.7%	5.3%	7.2%	7.0%
Conventional										
Pelican Lake	**5.9%**	3.2%	7.7%	5.8%	6.2%	5.0%	4.5%	6.6%	4.2%	4.5%
Weyburn	**19.6%**	16.8%	22.3%	20.3%	18.3%	20.7%	17.9%	19.8%	21.4%	23.3%
Other	**6.5%**	7.4%	6.8%	6.0%	5.7%	7.2%	7.1%	6.6%	6.8%	8.3%
Natural Gas Liquids	**1.9%**	1.9%	2.9%	2.5%	0.2%	2.0%	2.3%	2.5%	1.7%	1.7%
Natural Gas	**1.4%**	1.2%	1.8%	1.2%	1.7%	1.2%	0.9%	0.8%	0.4%	2.5%

REFINING	2013					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Refinery Operations (1)										
Crude oil capacity (2) *(Mbbls/d)*	**457**	457	457	457	457	452	452	452	452	452
Crude oil runs *(Mbbls/d)*	**442**	447	464	439	416	412	311	442	451	445
Heavy Oil	**222**	221	240	230	197	198	155	210	229	199
Light/Medium	**220**	226	224	209	219	214	156	232	222	246
Crude utilization	**97%**	98%	101%	96%	91%	91%	69%	98%	100%	98%
Refined products *(Mbbls/d)*	**463**	469	487	457	439	433	330	463	473	465

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

(2) The official nameplate capacity of Wood River increased effective January 1, 2013 and January 1, 2014.

SELECTED AVERAGE BENCHMARK PRICES	2013					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Crude Oil Prices *(US$/bbl)*										
Brent	**108.70**	109.35	109.65	103.35	112.64	111.68	110.13	109.42	108.76	118.45
West Texas Intermediate ("WTI")	**98.05**	97.61	105.81	94.17	94.36	94.15	88.23	92.20	93.35	103.03
Differential Brent Futures-WTI	**10.65**	11.74	3.84	9.18	18.28	17.53	21.90	17.22	15.41	15.42
Western Canadian Select ("WCS")	**72.85**	65.41	88.33	75.01	62.40	73.12	70.12	70.48	70.48	81.61
Differential – WTI-WCS	**25.20**	32.20	17.48	19.16	31.96	21.03	18.11	21.72	22.87	21.42
Condensate – (C5 @ Edmonton)	**101.77**	94.37	103.79	101.45	107.23	100.88	98.14	96.12	99.32	110.16
Differential – WTI-Condensate (premium)/discount	**(3.72)**	3.24	2.02	(7.28)	(12.87)	(6.73)	(9.91)	(3.92)	(5.97)	(7.13)
Refining Margins 3-2-1 Crack Spreads (3) *(US$/bbl)*										
Chicago	**21.77**	12.29	16.19	31.06	27.53	27.76	28.18	35.64	28.20	19.00
Midwest Combined (Group 3)	**20.80**	10.66	17.35	27.24	27.93	28.56	28.49	35.99	28.28	21.50
Natural Gas Prices										
AECO *($/Mcf)*	**3.17**	3.15	2.82	3.59	3.08	2.41	3.06	2.19	1.84	2.52
NYMEX *(US$/Mcf)*	**3.65**	3.60	3.58	4.09	3.34	2.79	3.40	2.81	2.22	2.74
Differential – NYMEX-AECO *(US$/Mcf)*	**0.58**	0.59	0.89	0.56	0.27	0.38	0.31	0.61	0.39	0.21

(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").

OPERATING STATISTICS – BEFORE ROYALTIES (continued)

PER-UNIT RESULTS

(excluding impact of Realized Gain (Loss) on Risk Management)	2013					2012				
	Year	Q4	Q3	Q2	Q1	*Year*	Q4	Q3	Q2	Q1
Heavy Oil – Foster Creek [4] *($/bbl)*										
Price	**66.30**	59.39	87.49	68.17	52.60	64.55	59.93	63.95	63.83	70.71
Royalties	**3.73**	3.56	6.31	3.87	1.47	7.36	4.55	11.79	2.85	9.54
Transportation and Blending	**2.36**	3.21	4.37	0.04	1.89	2.41	2.91	2.38	1.91	2.38
Operating	**15.77**	15.90	17.12	16.19	14.03	11.99	11.26	11.50	12.49	12.85
Netback	**44.44**	36.72	59.69	48.07	35.21	42.79	41.21	38.28	46.58	45.94
Heavy Oil – Christina Lake [4] *($/bbl)*										
Price	**51.26**	44.36	74.98	52.61	33.41	47.73	43.37	52.91	44.57	52.58
Royalties	**3.25**	3.22	5.06	2.71	1.69	2.72	2.32	2.61	2.90	3.37
Transportation and Blending	**3.55**	3.29	3.16	4.45	3.67	3.79	3.00	4.00	4.12	4.51
Operating	**12.47**	10.57	11.46	16.83	12.93	12.95	11.42	13.59	12.52	15.33
Netback	**31.99**	27.28	55.30	28.62	15.12	28.27	26.63	32.71	25.03	29.37
Total Heavy Oil – Oil Sands [4] *($/bbl)*										
Price	**59.10**	51.34	81.16	61.88	44.01	58.61	53.02	60.35	57.02	65.23
Royalties	**3.50**	3.37	5.68	3.40	1.57	5.72	3.62	8.80	2.87	7.68
Transportation and Blending	**2.93**	3.25	3.76	1.82	2.69	2.90	2.95	2.91	2.69	3.02
Operating	**14.19**	13.04	14.26	16.45	13.53	12.33	11.33	12.17	12.52	13.60
Netback	**38.48**	31.68	57.46	40.21	26.22	37.66	35.12	36.47	38.94	40.93
Heavy Oil – Pelican Lake [4] *($/bbl)*										
Price	**70.09**	64.52	88.08	72.32	54.30	69.23	64.37	66.75	66.42	78.50
Royalties	**4.00**	1.97	6.64	4.08	3.22	3.34	2.82	4.34	2.68	3.37
Transportation and Blending	**2.41**	2.79	2.18	2.58	2.07	2.15	1.23	1.09	3.54	2.88
Operating	**20.65**	21.22	19.90	22.21	19.23	17.08	17.20	17.47	17.71	16.05
Netback	**43.03**	38.54	59.36	43.45	29.78	46.66	43.12	43.85	42.49	56.20
Total Heavy Oil – Conventional [4] *($/bbl)*										
Price	**70.31**	64.55	87.50	71.73	57.42	69.76	64.52	67.25	66.95	79.37
Royalties	**6.08**	5.31	8.83	5.50	4.65	6.06	5.26	6.05	5.46	7.33
Transportation and Blending	**2.60**	2.69	2.51	2.58	2.63	2.16	1.69	1.55	3.01	2.44
Operating	**19.32**	19.76	18.51	20.30	18.72	16.32	14.91	17.09	16.61	16.67
Production and Mineral Taxes	**0.13**	0.05	0.21	0.12	0.13	0.10	0.13	0.10	0.10	0.06
Netback	**42.18**	36.74	57.44	43.23	31.29	45.12	42.53	42.46	41.77	52.87
Total Heavy Oil [4] *($/bbl)*										
Price	**62.23**	54.61	82.97	64.91	47.82	62.05	56.22	62.45	60.13	70.08
Royalties	**4.22**	3.85	6.58	4.05	2.45	5.83	4.07	7.96	3.68	7.56
Transportation and Blending	**2.84**	3.11	3.40	2.06	2.67	2.67	2.60	2.50	2.79	2.82
Operating	**15.62**	14.70	15.47	17.63	15.01	13.56	12.33	13.66	13.80	14.65
Production and Mineral Taxes	**0.04**	0.01	0.06	0.04	0.04	0.03	0.04	0.03	0.03	0.02
Netback	**39.51**	32.94	57.46	41.13	27.65	39.96	37.18	38.30	39.83	45.03
Light and Medium Oil *($/bbl)*										
Price	**86.30**	82.12	100.64	86.84	76.77	78.99	75.27	76.06	76.16	88.45
Royalties	**8.28**	6.58	11.01	8.61	7.05	8.09	6.92	7.53	7.98	9.94
Transportation and Blending	**4.35**	5.15	4.58	4.37	3.39	2.65	2.39	2.36	3.02	2.83
Operating	**16.23**	17.26	15.06	16.32	16.26	15.51	15.63	16.27	14.76	15.36
Production and Mineral Taxes	**2.30**	1.26	2.80	2.64	2.46	2.44	2.51	2.35	2.34	2.57
Netback	**55.14**	51.87	67.19	54.90	47.61	50.30	47.82	47.55	48.06	57.75

(4) 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 annual cost of condensate for 2013 is as follows: Foster Creek – $42.41/bbl; Christina Lake – $45.25/bbl; Heavy Oil – Oil Sands – $43.77/bbl; Pelican Lake – $15.59/bbl; Heavy Oil – Conventional – $14.60/bbl and Total Heavy Oil – $35.63/bbl.

OPERATING STATISTICS – BEFORE ROYALTIES (continued)

PER-UNIT RESULTS *(excluding impact of Realized Gain (Loss) on Risk Management)*	**2013**					2012				
	Year	Q4	Q3	Q2	Q1	Year	Q4	Q3	Q2	Q1
Total Crude Oil *($/bbl)*										
Price	**67.05**	59.41	86.41	69.75	54.02	65.76	60.10	65.37	63.91	74.22
Royalties	**5.03**	4.33	7.44	5.05	3.43	6.32	4.65	7.87	4.69	8.10
Transportation and Blending	**3.14**	3.47	3.63	2.57	2.82	2.66	2.55	2.47	2.84	2.83
Operating	**15.74**	15.15	15.39	17.34	15.27	13.99	13.00	14.22	14.03	14.81
Production and Mineral Taxes	**0.49**	0.23	0.59	0.61	0.56	0.56	0.54	0.53	0.58	0.59
Netback	**42.65**	36.23	59.36	44.18	31.94	42.23	39.36	40.28	41.77	47.89
Natural Gas Liquids *($/bbl)*										
Price	**60.34**	59.39	65.71	46.44	68.88	69.54	65.89	61.53	65.52	83.36
Royalties	**1.13**	1.14	1.92	1.17	0.12	1.42	1.52	1.55	1.13	1.45
Netback	**59.21**	58.25	63.79	45.27	68.76	68.12	64.37	59.98	64.39	81.91
Total Liquids *($/bbl)*										
Price	**67.01**	59.41	86.28	69.61	54.10	65.79	60.13	65.35	63.92	74.28
Royalties	**5.01**	4.31	7.40	5.03	3.42	6.29	4.64	7.83	4.67	8.05
Transportation and Blending	**3.12**	3.45	3.61	2.55	2.81	2.65	2.54	2.45	2.82	2.81
Operating	**15.65**	15.06	15.29	17.24	15.19	13.90	12.93	14.14	13.93	14.71
Production and Mineral Taxes	**0.48**	0.23	0.59	0.61	0.55	0.56	0.54	0.53	0.57	0.59
Netback	**42.75**	36.36	59.39	44.18	32.13	42.39	39.48	40.40	41.93	48.12
Total Natural Gas *($/Mcf)*										
Price	**3.20**	3.21	2.83	3.50	3.25	2.42	2.97	2.30	1.92	2.50
Royalties	**0.04**	0.04	0.05	0.04	0.05	0.03	0.02	0.02	0.01	0.06
Transportation and Blending	**0.11**	0.11	0.10	0.08	0.15	0.10	0.10	0.08	0.08	0.13
Operating	**1.16**	1.23	1.13	1.16	1.14	1.10	1.29	1.08	0.98	1.08
Production and Mineral Taxes	**0.02**	0.02	0.03	(0.01)	0.03	0.01	(0.01)	0.02	0.02	0.02
Netback	**1.87**	1.81	1.52	2.23	1.88	1.18	1.57	1.10	0.83	1.21
Total [(1)] *($/BOE)*										
Price	**51.23**	47.23	63.12	52.55	42.52	46.60	45.50	46.61	43.25	50.84
Royalties	**3.44**	3.07	5.02	3.35	2.38	4.00	3.08	5.02	2.84	5.00
Transportation and Blending	**2.31**	2.60	2.60	1.82	2.17	1.88	1.86	1.74	1.90	2.00
Operating	**12.79**	12.73	12.44	13.64	12.39	11.18	11.12	11.35	10.75	11.46
Production and Mineral Taxes	**0.36**	0.19	0.45	0.38	0.42	0.38	0.33	0.38	0.40	0.40
Netback	**32.33**	28.64	42.61	33.36	25.16	29.16	29.11	28.12	27.36	31.98

Impact of Long-Term Incentives Costs (Recovery) on Operating Costs *($/BOE)*	**0.12**	0.06	0.23	0.07	0.10	0.16	0.05	0.32	(0.17)	0.42

Impact of Realized Gain (Loss) on Risk Management										
Liquids *($/bbl)*	**1.09**	2.77	(2.02)	0.72	2.62	1.39	3.35	2.02	1.64	(1.67)
Natural Gas *($/Mcf)*	**0.32**	0.36	0.38	0.18	0.39	1.14	0.89	1.24	1.39	1.03
Total [(1)] *($/BOE)*	**1.37**	2.58	(0.58)	0.84	2.52	3.42	4.05	3.98	4.27	1.44

(1) 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, 2013 ("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 AT DECEMBER 31, 2013

(Forecast Prices and Costs)

Before Royalties [1]

Reserves Category	*Bitumen* *(MMbbls)*	*Heavy Oil* *(MMbbls)*	*Light & Medium Oil & NGLs* *(MMbbls)*	*Natural Gas & CBM* *(Bcf)*
Proved Reserves				
Developed Producing	192	129	89	834
Developed Non-Producing	25	3	11	27
Undeveloped	1,629	47	15	4
Total Proved Reserves	1,846	179	115	865
Probable Reserves	683	140	50	300
Total Proved plus Probable Reserves	2,529	319	165	1,165

After Royalties [2]

Reserves Category	*Bitumen* *(MMbbls)*	*Heavy Oil* *(MMbbls)*	*Light & Medium Oil & NGLs* *(MMbbls)*	*Natural Gas & CBM* *(Bcf)*
Proved Reserves				
Developed Producing	149	108	78	846
Developed Non-Producing	18	3	8	27
Undeveloped	1,241	40	12	4
Total Proved Reserves	1,408	151	98	877
Probable Reserves	522	107	42	283
Total Proved plus Probable Reserves	1,930	258	140	1,160

Notes:

(1) Does not include Royalty Interest Reserves.

(2) Includes Royalty Interest Reserves.

Royalty Interest

Reserves Category	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil & NGLs (MMbbls)	Natural Gas & CBM (Bcf)
Proved Reserves				
Developed Producing	–	1	6	42
Developed Non-Producing	–	–	–	–
Undeveloped	–	–	–	–
Total Proved Reserves	–	1	6	42
Probable Reserves	–	–	2	11
Total Proved plus Probable Reserves	–	1	8	53

SUMMARY OF NET PRESENT VALUE OF FUTURE NET REVENUE AT DECEMBER 31, 2013

(Forecast Prices and Costs)

Before Income Taxes

	Discounted at %/year ($ millions)					Unit Value Discounted at 10%(1)
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**	**$/BOE**
Proved Reserves						
Developed Producing	15,530	12,761	10,868	9,514	8,498	22.81
Developed Non-Producing	1,467	1,042	802	644	536	23.84
Undeveloped	48,111	22,625	11,899	6,710	3,915	9.20
Total Proved Reserves	65,108	36,428	23,569	16,868	12,949	13.07
Probable Reserves	28,265	13,055	6,916	4,079	2,599	9.63
Total Proved plus Probable Reserves	93,373	49,483	30,485	20,947	15,548	12.09

Note:

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

After Income Taxes (1)

	Discounted at %/year ($ millions)				
Reserves Category	**0%**	**5%**	**10%**	**15%**	**20%**
Proved Reserves					
Developed Producing	12,564	10,370	8,854	7,765	6,946
Developed Non-Producing	1,103	782	603	487	407
Undeveloped	36,916	17,043	8,842	4,920	2,827
Total Proved Reserves	50,583	28,195	18,299	13,172	10,180
Probable Reserves	21,448	9,785	5,105	2,966	1,864
Total Proved plus Probable Reserves	72,031	37,980	23,404	16,138	12,044

Note:

(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 our Consolidated Financial Statements and MD&A for the year ended December 31, 2013.

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

RESERVES RECONCILIATION

The following tables provide a reconciliation of our Company Interest Before Royalties reserves for bitumen, heavy oil, light and medium oil and NGLs, and natural gas for the year ended December 31, 2013, presented using forecast prices and costs. All reserves are located in Canada.

COMPANY INTEREST BEFORE ROYALTIES
RESERVES RECONCILIATION BY PRINCIPAL PRODUCT TYPE AND RESERVES CATEGORY

(Forecast Prices and Costs)

Proved

	Bitumen (MMbbls)	*Heavy Oil* (MMbbls)	*Light & Medium Oil & NGLs* (MMbbls)	*Natural Gas & CBM* (Bcf)
December 31, 2012	1,717	184	115	955
Extensions and Improved Recovery	134	21	11	24
Discoveries	–	–	–	–
Technical Revisions	32	(12)	6	76
Economic Factors	–	–	–	–
Acquisitions	–	–	–	–
Dispositions	–	–	(5)	–
Production [1]	(37)	(14)	(12)	(190)
December 31, 2013	1,846	179	115	865

Probable

	Bitumen (MMbbls)	*Heavy Oil* (MMbbls)	*Light & Medium Oil & NGLs* (MMbbls)	*Natural Gas & CBM* (Bcf)
December 31, 2012	676	105	56	338
Extensions and Improved Recovery	28	55	–	5
Discoveries	78	–	–	–
Technical Revisions	(99)	(20)	(4)	(43)
Economic Factors	–	–	–	–
Acquisitions	–	–	–	–
Dispositions	–	–	(2)	–
Production [1]	–	–	–	–
December 31, 2013	683	140	50	300

Proved plus Probable

	Bitumen (MMbbls)	*Heavy Oil* (MMbbls)	*Light & Medium Oil & NGLs* (MMbbls)	*Natural Gas & CBM* (Bcf)
December 31, 2012	2,393	289	171	1,293
Extensions and Improved Recovery	162	76	11	29
Discoveries	78	–	–	–
Technical Revisions	(67)	(32)	2	33
Economic Factors	–	–	–	–
Acquisitions	–	–	–	–
Dispositions	–	–	(7)	–
Production [1]	(37)	(14)	(12)	(190)
December 31, 2013	2,529	319	165	1,165

Note:

(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 our share of gas volumes provided to FCCL for steam generation, but does not include Royalty Interest Production.

Economic Contingent and Prospective Resources

Company Interest Before Royalties, *(billions of barrels)*	Bitumen	
	December 31, 2013	December 31, 2012
Economic Contingent Resources [1]		
Best Estimate	**9.8**	9.6
Prospective Resources [2]		
Best Estimate	**7.5**	8.5

Notes:

(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 our gross participation and net interest in wells drilled for the periods indicated:

Exploration Wells Drilled

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2013:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	6	6	–	–	–	–	6	6	9	15	6
Total Canada	6	6	–	–	–	–	6	6	9	15	6
2012:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	8	7	–	–	–	–	8	7	20	28	7
Total Canada	8	7	–	–	–	–	8	7	20	28	7
2011:											
Oil Sands	–	–	–	–	–	–	–	–	–	–	–
Conventional	24	22	–	–	2	2	26	24	40	66	24
Total Canada	24	22	–	–	2	2	26	24	40	66	24

Development Wells Drilled

	Oil		Gas		Dry & Abandoned		Total Working Interest		Royalty	Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Gross	Net
2013:											
Oil Sands	91	46	–	–	–	–	91	46	3	94	46
Conventional	215	206	–	–	2	2	217	208	117	334	208
Total Canada	306	252	–	–	2	2	308	254	120	428	254
2012:											
Oil Sands	61	31	–	–	–	–	61	31	57	118	31
Conventional	349	345	–	–	1	1	350	346	129	479	346
Total Canada	410	376	–	–	1	1	411	377	186	597	377
2011:											
Oil Sands	40	20	3	3	–	–	43	23	87	130	23
Conventional	343	334	66	65	4	4	413	403	156	569	403
Total Canada	383	354	69	68	4	4	456	426	243	699	426

During the year ended December 31, 2013, Oil Sands drilled 339 gross stratigraphic test wells (210 net wells) and Conventional drilled 54 gross stratigraphic test wells (54 net wells).

During the year ended December 31, 2013, Oil Sands drilled 27 gross service wells (17 net wells) and Conventional drilled 80 gross service wells (75 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 our landholdings at December 31, 2013:

Landholdings

(thousands of acres)	Developed		Undeveloped [1]		Total [2]	
	Gross	Net	Gross	Net	Gross	Net
Alberta:						
Oil Sands						
– Crown [3]	483	382	1,824	1,368	2,307	1,750
Conventional						
– Fee [4]	1,933	1,933	440	440	2,373	2,373
– Crown [3]	1,150	1,046	747	683	1,897	1,729
– Freehold [5]	71	60	15	14	86	74
Total Alberta	3,637	3,421	3,026	2,505	6,663	5,926
Saskatchewan:						
Oil Sands						
– Crown [3]	–	–	64	64	64	64
Conventional						
– Fee [4]	80	80	426	426	506	506
– Crown [3]	48	33	180	162	228	195
– Freehold [5]	14	10	7	3	21	13
Total Saskatchewan	142	123	677	655	819	778
Manitoba:						
Conventional – Fee [4]	4	4	263	263	267	267
Total Manitoba	4	4	263	263	267	267
Total	3,783	3,548	3,966	3,423	7,749	6,971

Notes:

(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) This table excludes approximately 2.4 million gross acres under lease or sublease, reserving to us, royalties or other interests.

(3) Crown/Federal lands are those lands owned by the federal or provincial government or the First Nations, in which we have purchased a working interest lease.

(4) Fee lands are those lands in which we have 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 us 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", "target", "project", "could", "focus", "goal", "outlook", "potential", "may", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related milestones and schedules, projected future value or net asset value, projections for 2014 and future years, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, expected reserves and contingent and prospective resources, broadening market access, improving cost structures, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

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

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

2014 guidance, updated February 13, 2014, available at cenovus.com, is based on an average diluted number of shares outstanding of approximately 757 million. It assumes: Brent US$105.00/bbl, WTI of US$102.00/bbl; Western Canada Select of US$76.00/bbl; NYMEX of US$4.00/MMBtu; AECO of $3.30/GJ; Chicago 3-2-1 crack spread of US$13.50/bbl; exchange rate of $0.98 US$/C$. For the period 2015 to 2023, assumptions include: Brent US$105.00–US$110.00; WTI of US$100.00–US$106.00/bbl; Western Canada Select of C$81.00–C$91.00/bbl; NYMEX of US$4.25–US$4.75/MMBtu; AECO of C$3.70–C$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00–US$13.00; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 782 million.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; 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, 2013 (see Additional Information).

OIL AND GAS INFORMATION

Terminology The estimates of reserves and resources data and related information were prepared effective December 31, 2013 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, 2014 price forecast.

For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our Annual Information Form for the year ended December 31, 2013 (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) the production 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 2013 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 Form (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 \$32.97/BOE for the year ended December 31, 2013, \$25.48/BOE for the year ended December 31, 2012 and averaged \$22.57/BOE for the three years ended December 31, 2013. 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 \$40.85/BOE for the year ended December 31, 2013, \$20.04/BOE for the year ended December 31, 2012 and averaged \$17.56/BOE for the three years ended December 31, 2013. 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 13, 2014 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:

TM	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
MMBOE	million barrels of oil equivalent
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
MMcf/d	million cubic feet per day
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 or include any relevant direct and indirect subsidiary corporations and partnerships ("subsidiaries") of Cenovus, 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, 2013, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

Shareholder Information

ANNUAL MEETING

Shareholders are invited to attend the annual meeting to be held on Wednesday, April 30, 2014 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, ON M5J 2Y1

www.investorcentre.com/cenovus

Shareholder Inquiries by phone 1.866.332.8898 (North America, English & French) or 1.514.982.8717 (outside North America, English & 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 US 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 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
media.relations@cenovus.com

CENOVUS HEAD OFFICE

Cenovus Energy Inc.
500 Centre Street SE
PO Box 766
Calgary, Alberta, Canada
T2P 0M5
Phone: 403.766.2000
cenovus.com

EXECUTIVE OFFICERS

Brian C. Ferguson
President
& Chief Executive Officer

Harbir S. Chhina
Executive Vice-President,
Oil Sands

Kerry D. Dyte
Executive Vice-President,
General Counsel
& Corporate Secretary

Sheila M. McIntosh
Executive Vice-President,
Environment
& Corporate Affairs

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

John K. Brannan
Executive Vice-President
& Chief Operating Officer

Hayward J. Walls
Executive Vice-President,
Strategy & Organization
Development

BOARD OF DIRECTORS

Michael A. Grandin
Chair, Calgary, Alberta[3,7]

Patrick D. Daniel
Calgary, Alberta[1,2,3]

Wayne G. Thomson
Calgary, Alberta[3,4,5]

Ralph S. Cunningham
Houston, Texas[2,3,5]

Valerie A.A. Nielsen
Calgary, Alberta[1,3,4]

Charles M. Rampacek
Dallas, Texas[3,4,5]

Brian C. Ferguson
Calgary, Alberta[6]

Ian W. Delaney
Toronto, Ontario[2,3,5]

Colin Taylor
Toronto, Ontario[1,2,3]

(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

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 10-year business plan and continue to increase value for shareholders.

Cenovus Energy is a Canadian integrated oil company. We are committed to applying fresh, progressive thinking to safely and responsibly unlock energy resources the world needs.

WHY INVEST IN CENOVUS?

- **Industry-leading oil sands assets**
  These great assets support decades of profitable oil growth.
- **A track record of strong operational results**
  This has allowed us to be a leader in steam-assisted gravity drainage, or SAGD.
- **A manufacturing approach to oil development**
  This supports our industry-leading cost metrics and capital efficiencies.
- **A focus on innovation**
  This means we're continually improving our performance.
- **An integrated approach**
  This improves the stability of our overall cash flow despite the variability in commodity prices.
- **Financial strength**
  This provides us the flexibility to pursue our growth plans and support a strong and sustainable dividend.

Our operations include oil sands projects in northern Alberta, which use specialized methods to drill and pump the oil to the surface. As well, we have established natural gas and oil production in Alberta and Saskatchewan. We also have 50 percent ownership in two U.S. refineries.

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Calgary, Alberta
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