Canadian Natural

2014 ANNUAL REPORT

PREMIUM VALUE. DEFINED GROWTH. INDEPENDENT.

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VALUE CREATION

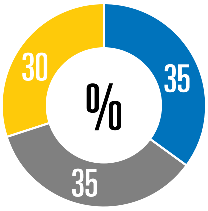
For Canadian Natural, 2014 marked our twenty-fifth year in operations after restructuring to an exploration and production company in the oil and gas industry. The year also highlighted the Company's strengths, which are predicated on a long-standing proven strategy and disciplined business approach. A strategy and business approach cultivated over our long history to maximize long-term value for shareholders.

Canadian Natural achieved record annual average production of over 790,000 BOE/d in 2014. A significant accomplishment with crude oil and NGL assets producing at record levels of over 530,000 bbl/d and natural gas assets producing 1,555 MMcf/d. Our strong operations were supported by favorable economic factors and our disciplined financial approach. As a result, the Company realized approximately $9.6 billion of cash flow from operations in 2014, contributing to our strong financial position.

The balance of our large and diverse asset base, our proven strategy and our balanced approach to capital allocation supports our transition to longer-life, low decline production. Canadian Natural is clearly in a very favorable position as we continue to execute our strategies and unlock significant value for shareholders.

BALANCED PORTFOLIO

Our proven business strategy is grounded by a belief in balance. We have built a large, diversified inventory of assets providing a balanced mix by segment, commodity type and production. The balance of our assets enables us to be flexible and nimble in response to changing business conditions. By employing a business approach that requires discipline and balance, we have the ability to weather industry cycles as we have options to reallocate capital, develop our asset base, make opportunistic acquisitions, repay debt or provide shareholder returns in the form of dividends or share purchases.



PRODUCTION MIX

- HEAVY CRUDE OIL & BITUMEN
- NATURAL GAS
- LIGHT CRUDE OIL, NGLs & SCO

LARGE, BALANCED, HIGH QUALITY, DIVERSE ASSET BASE

As at December 31, 2014, our Company Gross proved and probable reserves were 8.89 billion BOE, one of the largest reserve bases in the industry. Over the years we have built a tremendous resource base providing the foundation from which we derive our economic growth.

Our diversified, balanced resource base consists of both dry and liquids-rich natural gas, heavy crude oil, bitumen, medium and light crude oil and synthetic crude oil, which allows us to allocate capital to the highest return projects and generate strong field operating free cash flow.

LARGE ASSET BASE

		PRODUCTION (before royalties)	PROVED RESERVES (1)	PROVED PLUS PROBABLE RESERVES (1)
NORTH AMERICA				
OIL SANDS	THERMAL IN SITU	108 Mbbl/d	1,217 MMbbl (2)	2,312 MMbbl (2)
	MINING & UPGRADING	111 Mbbl/d	2,158 MMbbl (3)	3,593 MMbbl (3)
CRUDE OIL & NGLs		283 Mbbl/d	836 MMbbl	1,173 MMbbl
NATURAL GAS		1,527 MMcf/d	5,869 Bcf	7,926 Bcf
OFFSHORE AFRICA				
CRUDE OIL & NGLs		12 Mbbl/d	96 MMbbl	149 MMbbl
NATURAL GAS		21 MMcf/d	49 Bcf	98 Bcf
NORTH SEA				
CRUDE OIL & NGLs		17 Mbbl/d	204 MMbbl	308 MMbbl
NATURAL GAS		7 MMcf/d	83 Bcf	114 Bcf

(1) Company Gross (2) Bitumen (3) Synthetic Crude Oil

OUR FINANCIAL STRENGTH

Throughout 2014, Canadian Natural continued to focus on maintaining a strong financial position. With clear financial objectives and a focus on cost control, we exited the year with debt to book capitalization of 33% and debt to EBITDA of 1.3 times. We proactively manage our debt and ensure that the financial community understands our business plans, our capital and our operating flexibility, and our ability to react quickly as business conditions warrant. The Company's focus on managing a balanced financial program and generating strong cash flow helps to provide the appropriate financial resources for the near-, mid- and long-term.

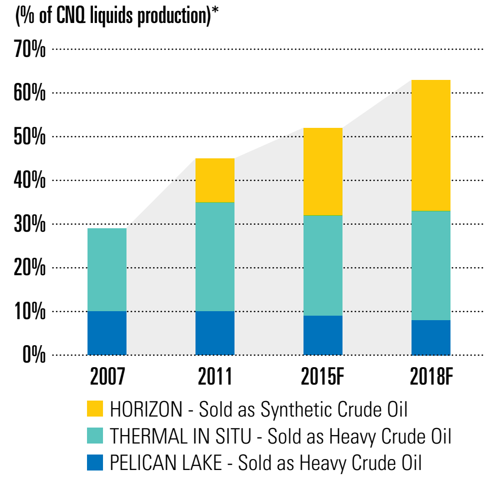
Debt to EBITDA		1.3x
Debt to Book Capitalization		33%
Bank Lines in Place	$	5.6 million
Available Bank Lines	$	2.6 million
Cash Flow from Operations*	$	9.6 billion
Per Common Share - basic	$	8.78
- diluted	$	8.74
Adjusted Earnings from Operations*	$	3.8 billion
Per Common Share - basic	$	3.49
- diluted	$	3.47

*As defined on page 2 in the notes of the 2014 Performance Highlights.

OUR TRANSITION TO A LONGER-LIFE, LOW DECLINE ASSET BASE

Canadian Natural's transformation to a longer-life, low decline asset base continued to take shape during 2014. In the third quarter, we expanded the Coker plant at Horizon Oil Sands ("Horizon"), which alleviated bottlenecks and added 12,000 bbl/d of synthetic crude oil productive capacity. Kirby South continued to progress toward 40,000 bbl/d of facility capacity, and Pelican Lake's outstanding reservoir performance achieved annual record production success of over 50,000 bbl/d.

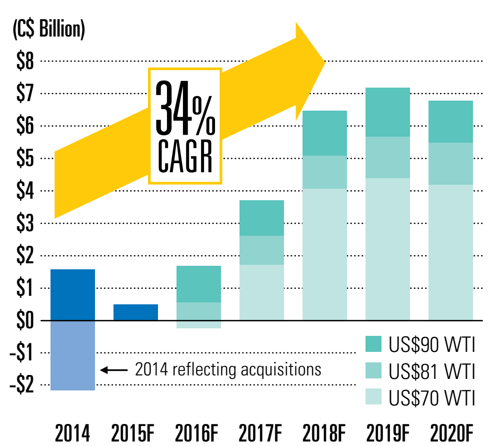
At the end of 2014, over 50% of our crude oil and NGL production came from longer-life assets. By 2018, longer-life, low decline production will constitute more than 60% of overall crude oil and NGL production. Our transition will result in increasing, sustainable free cash flow generation for years to come.



*2015F and 2018F based on company internal forecast as at March 2015 and November 2014 respectively. Dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation. See forward-looking disclosures on page 20 of the Management's Discussion and Analysis ("MD&A").

OUR SUSTAINABLE FREE CASH FLOW AND PROFITABLE GROWTH

The Company generated $9.6 billion of cash flow from operations in 2014. As we transition our asset base to longer-life, low decline production, our sustainable free cash flow will increase substantially over the coming years. Fundamental to maintaining this sustainable free cash flow growth is our strategy of balance. Balance in our product mix, where we operate and our business approach enable us to execute on our defined growth plan, a key to unlocking the value of our large reserve and resource base.



Note: Dependent upon economic and regulatory conditions, commodity prices, global economic factors, project sanction and capital allocation. Free cash flow represents cash flow (cash flow net of corporate costs, interest, foreign exchange and taxes) less capital before dividends and share purchases. CAGR represents 2014-2018F period. See page 19 and 20 for capital and pricing assumptions, and forward-looking disclosures.

UNLOCKING SHAREHOLDER VALUE

Canadian Natural is strong. We are well positioned to execute upon defined plans and deliver growing, sustainable free cash flow for years to come. As part of our proven strategy, we strive to economically grow production and effectively balance free cash flow allocation between resource development, opportunistic acquisitions, debt repayment, and returns to shareholders through dividends and share purchases.

We strive to achieve safe, effective, efficient, and environmentally responsible operations of our diverse, balanced reserve base. This reserve base is one of the largest in the industry and will deliver strong free cash flow over the long term. Importantly, it also allows us to transition the Company to a long-life, low decline asset base that will substantially and sustainably increase free cash flow. At the same time, Canadian Natural continues to maintain a strong balance sheet with a capacity to capture opportunities and weather commodity price volatility. Most important of all, we have the people, the expertise, and the experience to execute our programs and operate effectively and efficiently. Canadian Natural is clearly in a very favorable position as we continue to execute our strategies and unlock significant value for shareholders.

$0.90/SHARE

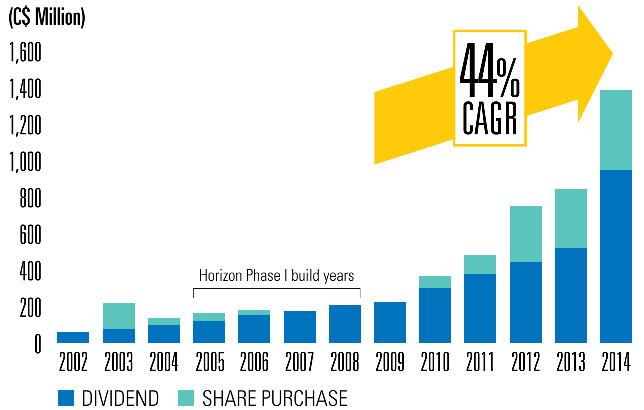
DECLARED IN 2014

80%

DIVIDEND INCREASE IN 2014

UNLOCKING SHAREHOLDER VALUE

Canadian Natural focuses on balanced and prudent capital allocation to maximize long-term value for shareholders.



Note: CAGR represents 2009-2014.

2014 PERFORMANCE HIGHLIGHTS

As the Company continues to progress the transition to a longer-life, low decline asset base, our balanced disciplined business approach generated record results in 2014. Canadian Natural achieved strong production and cash flow from operations, supported by our large, diverse asset base and dedicated teams.

		2014		2013		2012
FINANCIAL ($ millions, except per common share amounts)						
Product sales	$	**21,301**	$	17,945	$	16,195
Net earnings	$	**3,929**	$	2,270	$	1,892
Per common share – basic	$	**3.60**	$	2.08	$	1.72
– diluted	$	**3.58**	$	2.08	$	1.72
Adjusted net earnings from operations [1]	$	**3,811**	$	2,435	$	1,618
Per common share – basic	$	**3.49**	$	2.24	$	1.48
– diluted	$	**3.47**	$	2.23	$	1.47
Cash flow from operations [2]	$	**9,587**	$	7,477	$	6,013
Per common share – basic	$	**8.78**	$	6.87	$	5.48
– diluted	$	**8.74**	$	6.86	$	5.47
Capital expenditures, net of dispositions	$	**11,744**	$	7,274	$	6,308
Long-term debt [3]	$	**14,002**	$	9,661	$	8,736
Shareholders' equity	$	**28,891**	$	25,772	$	24,283
OPERATING						
Daily production, before royalties						
Crude oil and NGLs (Mbbl/d)						
North America – excluding Oil Sands Mining and Upgrading		**391**		344		326
North America – Oil Sands Mining and Upgrading		**111**		100		86
North Sea		**17**		18		20
Offshore Africa		**12**		16		19
		531		478		451
Natural gas (MMcf/d)						
North America		**1,527**		1,130		1,198
North Sea		**7**		4		2
Offshore Africa		**21**		24		20
		1,555		1,158		1,220
Barrels of oil equivalent (MBOE/d) [4]		**790**		671		655

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation to this measure is discussed in the MD&A.
(2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and repay debt. The derivation of this measure is discussed in the MD&A.
(3) Includes the current portion of long-term debt.
(4) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

	2014	2013	2012
Drilling activity (net wells) (1)			
North America	**1,112**	1,190	1,271
North Sea	**5**	1	-
Offshore Africa	**-**	-	-
	1,117	1,191	1,271
Core unproved property (thousands of net acres)			
North America	**20,583**	14,672	13,775
North Sea	**93**	110	128
Offshore Africa	**2,467**	2,467	4,307
	23,143	17,249	18,210
Company Gross proved plus probable reserves (2)			
Crude oil and NGLs (MMbbl)			
North America	**7,078**	6,495	6,431
North Sea	**308**	325	332
Offshore Africa	**149**	153	158
	7,535	6,973	6,921
Natural gas (Bcf)			
North America	**7,926**	5,881	5,574
North Sea	**114**	125	102
Offshore Africa	**98**	103	111
	8,138	6,109	5,787
Barrels of oil equivalent (MMBOE)	**8,891**	7,991	7,886

(1) Excludes net stratigraphic test and service wells.
(2) Year-end proved plus probable reserves were prepared using forecast prices and costs.

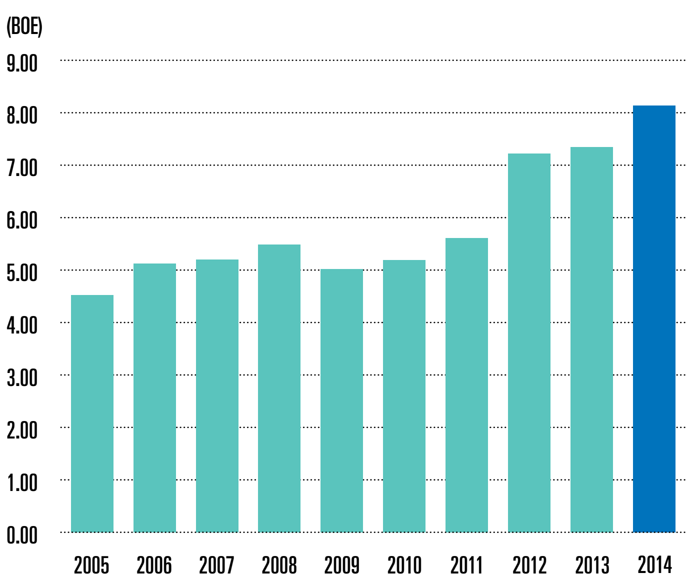
413%

2P RESERVE REPLACEMENT RATIO

31 YEARS

2P RESERVE LIFE INDEX

COMPANY GROSS 2P RESERVES PER SHARE



Note: Company Gross proved plus probable reserves prior to 2010 were prepared using constant prices and costs. Excludes Horizon SCO reserves prior to 2009.

LETTER TO OUR SHAREHOLDERS

2014 marked our twenty-fifth year of oil and gas operations and in reflection, the year constituted a range of successful and challenging events.

For Canadian Natural, we had a strong operating year, producing over 790 MBOE/d, we took the next step in our transition to longer-life, low decline assets with the completion of Phase 2A at Horizon, and we demonstrated our ability to allocate capital to value added acquisitions. As expected, heavy oil differentials narrowed during the year as a result of increased heavy crude oil demand and takeaway capacity.

In late 2014, we saw pricing conditions in the crude oil market deteriorate. However, we were able to demonstrate that our strategy, with a balanced and disciplined business approach continues to prove successful in all cycles of the commodity business. Our balanced capital allocation approach included returns to shareholders through an increase of 80% in our dividend over the previous year and share purchases of 10,095,000 common shares at an aggregate cost of $453 million. Finally we continued to maintain a strong financial position, one that will help us weather fluctuations in the market and continue to deliver long-term value to our shareholders.

SAFETY AND ENVIRONMENT

At Canadian Natural, we make safety a core value, not just a priority. We know that priorities can change, but core values do not. Safety, reliability and efficiency are incorporated into our work; our concepts, designs, construction, operations, and decommissioning and reclamation activities. We remain committed to continued improvement in our safety performance with the ultimate goal of no harm to people and no unsafe incidents. From an environmental perspective, we're focused on delivering proactive, environmentally responsible operations, where we continually drive to reduce our environmental footprint, and meet or exceed all regulatory requirements as well as our own internal targets. In 2015, the Company will continue to operate and execute with safety as a core value and remain proactive in delivering environmentally responsible operations.

ADDING VALUE IN 2014

Our strategy is proven. Through the prudent development of our diverse asset base and our demonstrated ability to capture opportunities, we have consistently added value to our shareholders. We remain focused on balance. Balance provides us flexibility in our capital allocation choices and allows us to be effective and efficient in our operations. This flexibility equates to a strong financial position, providing us the ability to withstand downturns in economic conditions such as significant changes in commodity prices, while executing on value adding opportunities.

In 2014, we continued to progress the transition of our portfolio to a longer-life, low decline asset base, while at the same time growing our asset base through opportunistic acquisitions. As at December 31, 2014, our proved plus probable reserves were 8.89 billion barrels of oil equivalent, one of the largest reserve bases in our industry. Our production mix remains balanced, drawing from our natural gas and crude oil assets. At the end of 2014, over 50% of our crude oil and NGL production came from longer-life assets. This continuing transition is less capital intensive, facilitating growth of sustainable free cash flow for many decades to come. We have the assets, the projects and the plan to deliver significant growth of long-life, low decline production going forward.

NATURAL GAS

Canadian Natural is the largest producer of natural gas in Canada. Supported by one of the largest land positions and significant infrastructure throughout Western Canada, our natural gas assets continue to be a strategic part of our production mix. Maintaining this strategic position and leveraging our experience enables us to maintain low operating costs in all pricing environments, ensuring we maximize returns for shareholders.

In 2014 we increased the production from our natural gas assets through the successful completion of several opportunistic acquisitions as well as the continued development of our existing liquids-rich asset base. These activities supported year-over-year growth in natural gas

790 MBOE/D	$9.6 BILLION
PRODUCTION	CASH FLOW FROM OPERATIONS

production of 34% from 2013 levels. In 2015 we target to preserve our land base through disciplined spending and will continue to develop our liquids-rich natural gas assets in Northeast BC and the Deep Basin.

LIGHT CRUDE OIL AND NGLS

NORTH AMERICA

In 2014, we continued to increase our North America light crude oil and NGL production through a successful drilling program and the completion of certain opportunistic acquisitions. Through added production volumes and the use of technology such as horizontal multi-fracs and leveraging of our expertise, we were able to grow light crude oil and NGL production 31% over 2013 levels. In 2015, we will target multiple formations in a focused drilling program centered on delivering value. We will continue to optimize our existing operations, improve operating costs and strengthen our netbacks while maximizing value for our shareholders.

INTERNATIONAL

Our international offshore assets remain a strategic component of our balanced, diverse asset base. These assets offer exposure to international pricing, provide us offshore expertise and deliver significant cash flow that supports the Company's transition to a longer-life, low decline asset base. Additionally these assets offer us offshore exploration upside such as our opportunities in Côte d'Ivoire and South Africa.

In Côte d'Ivoire, an exploration well on Block CI-514 was drilled in Q2/14 and encountered hydrocarbons; a second appraisal well is targeted for 2015. In South Africa, the operator commenced drilling on our 50% interest in Block 11B/12B in Q3/14. The well was drilled to a sufficient depth to retain the exploratory right and the operator, along with Canadian Natural, targets to re-enter the well in 2016. In Offshore Africa, development programs at both Espoir and Baobab are targeted to add economic production to the Company's growth profile in 2015.

In the North Sea, previously announced Brownfield Allowance drilling continued in 2014 and successfully contributed to production increases. With other volume adding initiatives undertaken in the North Sea, including the reinstatement of the Banff/Kyle Floating Production Storage and Offloading vessel in Q3/14, these two programs target to increase production in the North Sea in 2015.

HEAVY CRUDE OIL

PRIMARY PRODUCTION

Canadian Natural is the largest primary heavy crude oil producer in Canada, and our experienced teams and significant undeveloped land base continue to produce repeatable, proven performance. Our flexible and effective drilling programs deliver industry leading capital efficiencies and, along with low operating costs, provide strong netbacks and significant cash flow. In 2014, we achieved record average annual production in primary heavy crude oil of approximately 143,400 bbl/d, a 5% increase over 2013 levels. In 2015, primary heavy crude oil will continue to deliver economic production and significant free cash flow with our focused, flexible drilling program, well optimizations, zone recompletions and enhanced crude oil recovery opportunities.

PELICAN LAKE

Pelican Lake has one of the largest polymer floods in the world and is an important component in our transition to a longer-life, low decline asset base. At our leading edge polymer flood, the reservoir continues to respond positively with record annual production in 2014 averaging approximately 50,100 bbl/d, a 17% increase over 2013 levels. The technology driven polymer flood is targeted to require reduced reserves replacement capital as we target further increases in production in 2015 and beyond. This, along with our industry leading operating costs of less than $9.00/bbl will provide us with increasing free cash flow in the near-, mid- and long-term. A further testament to the success of our polymer flood and the value it generates for shareholders.

MARKETING

As the largest producer of heavy crude oil in Canada, Canadian Natural's marketing strategy aims to maximize realized pricing and shareholder value through a three-pronged approach. We blend various crude oil streams and diluents to better serve the needs of our refining customers, we support the expansion of export pipeline capacity and finally, we support and participate in projects which add conversion capacity for heavy crude oil and bitumen.

As expected, 2014 saw less volatility in the heavy crude oil differential. Supply and demand fundamentals became more balanced with additional heavy crude oil demand in the Chicago refining complex, increased takeaway capacity to the U.S. Gulf coast via the Flanagan South pipeline and the twinning of the Seaway pipeline. It is this balance that Canadian Natural looks to leverage through its participation in the Redwater refinery project. Canadian Natural owns 50% of the

HIGH QUALITY DIVERSIFIED PORTFOLIO

EFFECTIVE AND EFFICIENT OPERATIONS

DISCIPLINED BUSINESS APPROACH

50,000 bbl/d bitumen upgrader refinery project through its participation in the Redwater Partnership. The Redwater refinery is targeted to add bitumen conversion capacity in Alberta in 2017, contributing to improved heavy crude oil pricing, while generating a return to our shareholders.

OIL SANDS

THERMAL IN SITU

2014 was a year of continued execution and patience for the Company with regards to Primrose, our thermal in situ cyclic steam operations. At Primrose East, we filed our preliminary investigation report on the 2013 emulsions to surface with the regulator. With increased monitoring and modified steaming strategies in place, the regulator approved our steam flood application in Q3/14. In 2015, we will continue to steam flood approved areas and begin steaming under a low pressure cyclic steam process as proposed. At our Primrose North and South fields, we are able to employ cyclic pressure steaming, and the production response to our revised steaming strategies and increased monitoring has exceeded our expectations. Production at Primrose North and South was approximately 79,000 bbl/d, a 65% increase from 2013 levels.

At Kirby South, the first of several of our large commercial steam assisted gravity drainage ("SAGD") projects, thermal efficiencies are excellent as we ramp up to 40,000 bbl/d. Production in 2014 averaged approximately 15,200 bbl/d and we target to ramp up to facility capacity in the second half of 2015. Kirby South is a key part of our staged thermal in situ development plan and transformation to a longer-life, low decline asset base. Canadian Natural targets to increase thermal in situ facility capacity by 40,000 bbl/d to 60,000 bbl/d every 2 to 3 years to approximately 520,000 bbl/d, once economic conditions warrant investment.

MINING AND UPGRADING

At Horizon, the major component of our transition to a longer-life, low decline asset base, 2014 brought continued focus on safe, steady, and reliable production and a very meaningful improvement in plant performance. Through greater operational discipline and further reliability enhancements, the operations team at Horizon achieved an industry leading average utilization rate for the upgrader of 89%. With improved utilization, average annual production from this world class asset reached approximately 110,600 bbl/d of synthetic crude oil ("SCO"), a 10% increase over 2013 levels.

Subsequent to the successful completion of Phase 2A in which additional coker capacity and equipment were added, the Horizon plant's name plate capacity increased to 133,000 bbl/d. The strong performance of new equipment along with the implementation of an optimized mining strategy have enhanced the stability of the extraction and upgrading processes, further increasing plant name capacity to 137,000 bbl/d. Consequently, production volumes following the commissioning of Phase 2A averaged approximately 136,000 bbl/d of SCO.

In 2015, we will continue to focus on operational discipline and safe, steady and reliable production. As a result of facility redundancy added during the Phase 2A completion, combined with our more effective mining strategy, less maintenance stress will be placed on the downstream equipment and overall performance of the Horizon plant will increase. This performance improvement has enabled us to reduce the scope of the 35 day maintenance turnaround to six days, targeted for the latter half of 2015. Remaining work is now targeted for May 2016. The shortened turnaround allows for an additional 10,000 bbl/d of SCO production in 2015, increasing our annual production guidance to range from 121,000 bbl/d to 131,000 bbl/d. We will also increase operating cost efficiencies through operations optimization and higher production volumes.

Canadian Natural's phased expansion strategy is working. The Phase 2A expansion added 12,000 bbl/d of SCO productive capacity, and at year end the entire Phase 2/3 project is now 56% physically complete. With approximately $6.0 billion targeted to be invested in aggregate over the next 3 years, the completion of the staged expansion to 250,000 bbl/d of productive capacity of SCO is in sight.

We will now be able to complete the tie-in work for Phase 2B during the 2016 maintenance turnaround as a result of continued strong project execution and excellent construction performance of the Phase 2B expansion. Production volumes from Phase 2B are now targeted to incrementally increase earlier in 2016 than previously expected. After the May 2016 turnaround, volumes are expected to increase by 4,000 bbl/d in Q3/16 and 10,000 bbl/d in Q4/16, above the ramp up of the originally planned production levels. The completion of Phase 2B and Phase 3 will culminate in the addition of 45,000 bbl/d in late 2016 and 80,000 bbl/d of SCO productive capacity in late 2017. As the major component of our longer-life, low decline asset base, Horizon will generate significant free cash flow and value for our shareholders well into the future.

CANADIAN NATURAL'S STRATEGIC ADVANTAGE

In 2014, we continued to add value for our shareholders through the ramp up of our Kirby South project and the completion and commissioning of Phase 2A at Horizon. These two elements are representative of our continued progression to a longer-life, low decline asset base, one that will yield growing, sustainable free cash flow for decades to come. Sustainable free cash flow that will support further resource development, a strong balance sheet, acquisition opportunities and returns to shareholders through share purchases and sustainable dividends.

Today the industry is faced with crude oil pricing challenges that began in late 2014 and may persist until supply and demand can find an appropriate balance. Meanwhile, Canadian Natural is poised to withstand the uncertainties of today's market. In 2015, we will continue to execute on our proven strategy and balanced business approach. We have built a large, diversified inventory of assets providing a balanced mix by segment, commodity type and production. This balanced production mix gives us the flexibility to allocate capital to the highest rate of return projects in our portfolio, whether it be a drilling opportunity, an opportunistic acquisition or to further strengthen our balance sheet. Our capital and operating flexibility, and the ability to react quickly to capture opportunities and withstand commodity price volatility are fundamental to the Company's success in maximizing long-term shareholder value.

The Company will continue to focus on maintaining a strong financial position as we continue to grow production. We have clear longstanding financial objectives designed to protect our balance sheet and maintain effective and efficient operations with a focus on cost control. We proactively manage our debt and ensure that the financial community understands our business plans, our capital and operating flexibility, and our ability to react quickly as business conditions warrant. This focus on effective and efficient operations facilitates favorable free cash flow generation during all commodity price cycles.

A disciplined yet nimble and flexible financial approach to our operations ensures we are able to adapt quickly to changing conditions. As a result, the Company's focus on managing a balanced financial program and generating strong cash flow helps to provide the appropriate financial resources for the near-, mid- and long-term.

Canadian Natural is well positioned to execute upon our defined plans and deliver substantial and sustainable free cash flow for years to come. With our dedicated teams and committed, experienced management, and our adherence to safe and environmentally responsible operations, we will continue to strive to deliver long-term value for shareholders, effectively and efficiently. As a result, we will remain the premium value, defined growth independent.

N. MURRAY EDWARDS	STEVE W. LAUT	TIM S. MCKAY	DOUGLAS A. PROLL	COREY B. BIEBER
Chairman	President	Chief Operating Officer	Executive Vice-President	Chief Financial Officer & Senior Vice-President, Finance

OUR WORLD-CLASS TEAM

OUR PROVEN STRATEGY AND DISCIPLINED BUSINESS APPROACH ARE SUPPORTED BY OUR DEDICATED TEAMS AND EXPERIENCED MANAGEMENT TEAM.

To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity.

G. Aalders, E. Aasen, A. Abadier, L. Abadier, Z. Abbas, T. Abbasi, D. Abbott, M. Abdeldayem, A. Abeda, M. Abeda, W. Abeda, A. Abeer, D. Abel, R. Abel, P. Abercrombie, R. Abrams, J. Abramyk, N. Abro, S. Abroskin, M. Abuelteen, C. Acharya, D. Acheson, J. Acosta, T. Adair, I. Adam, S. Adam, W. Adam, B. Adams, C. Adams, D. Adams, K. Adams, M. Adams, D. Adamson, C. Adan, R. Adan, D. Addinall, A. Adebayo, Y. Adebayo, B. Adeleye, M. Aden, A. Adesanya, M. Aditiakusuma, R. Adzabe Ella, J. Agate, A. Agnihotri, K. Agombar, I. Agu, U. Agu, A. Agustin, M. Ahmad, S. Ahmad, A. Ahmadi, M. Ahmadi, F. Ahmadloo, A. Ahmari, A. Ahmed, R. Ahmed, T. Aickelin, R. Aidoo, R. Aikens, G. Ailsby, K. Aitchison, K. Aitken, T. Ajayi, V. Akella, S. Akhtar, K. Akinde, A. Akinsanya, R. Akkineni, J. Akolkar, S. Akolkar, K. Akpan, D. Albert, J. Alcala, E. Alconcel, D. Alderdice, S. AlDhabbi, B. Alexander, D. Alexander, J. Alexander, P. Alexander, V. Alexander, E. Algazina, A. Ali, G. Ali, K. Ali, S. Ali, R. Aliazas, H. 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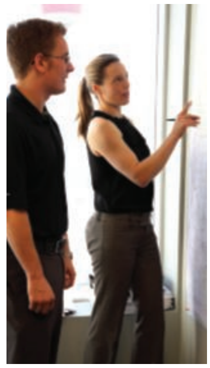

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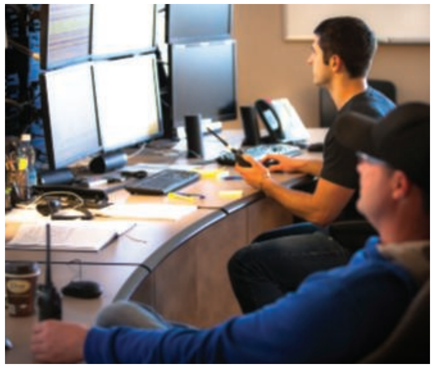

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Salazar, D. Salazar, E. Salazar, E. Saleh, O. Saleh, M. Salehi, J. Sali, C. Salim, C. Salisbury, E. Saller, M. Salman, E. Salmon, P. Salomon, A. Salonga, G. Salt, B. Saluk, R. Salyn, A. Samadi, N. Samer, S. Samimi, S. Sampanthamoorthy, L. Sampsel, H. Sampson, S. Samy, V. Sanchala, R. Sanchez Hernandez, P. Sanders, D. Sanderson, L. Sanderson, S. Sandhar, N. Sandhawalia, G. Sando, T. Sanelli, G. Sanford, E. Sangroniz, N. Sankaran, R. Sanregret, T. Santos, J. Sanyal, S. Saran, Z. Saran, R. Sarauskas, D. Saretsky, S. Sarkar, D. Sarmiento, A. Sartori, M. Sartoris, M. Sas, S. Sashuk, T. Sather, W. Sather, E. Saucier, J. Saucier, S. Sauder, G. Saunders, L. Saunders, R. Saunders, S. Saurette, C. Sauve, J. Savage, B. Savla, D. Savoie, L. Savoie, M. Savoie, C. Savostianik, A. Savtchenko, M. Sawka, B. Sawler, C. Sayer, R. Sayer, K. Scagliarini, R. Scammell, B. Scarth, R. Schaap, K. Schachtel, B. Schade, J. Schafer, R. Schafer, T. Schafer, D. Schaffer, B. Schamehorn, C. Schaub, P. Schaub, A. Schaufele, J. Schechtel, P. Scheffelmaier, M. Schellenberg, L. Schelske, D. Schenk, L. Scheper, C. Scherger, C. Scheu, D. Schick, S. Schick, M. Schiller, R. Schlachter, D. Schledt, B. Schmaltz, G. Schmidt, J. Schmidt, K. Schmidt, N. Schmidt, J. Schmitz, H. Schnaier, D. Schneider, G. Schneider, J. Schneider, P. Schneider, S. Schneider, B. Schnell, C. Schnepf, J. Schnieder, R. Schnieder, C. Schnurer, K. Schnurer, J. Schoengut, B. Schoepp, S. Schofield, R. Schonheiter, L. Schonhoffer, R. Schrage, K. Schram, C. Schrauwen, K. Schroeder, S. Schroeder, R. Schuh, N. Schuler, E. Schulte, S. Schultheiss, J. Schultz, T. Schulz, K. Schumacher, D. Schutte, D. Schwank, L. Schwetz, J. Schwindt, J. Scollard, D. Scott, E. Scott, J. Scott, K. Scott, L. Scott, M. Scott, R. Scott, S. Scott, R. Scoville, M. Scragg, A. Scriba, R. Scrimshaw, G. Scripca, C. Scullion, I. Scully, S. Seabrook, M. Seafoot, G. Seal, G. Seaton, J. Seaton, J. Sebastian, M. Sebastian, D. Seel, C. Seely, L. Seemann, B. Seewitz, M. Seguin, S. Sehgal, L. Sehn, M. Sehn, K. Seidel, P. Seipp, R. Sekel, B. Sekulich, E. Sekura, D. Selby, K. Self, M. Sell, K. Sellick, K. Selman, M. Selman, A. Semchanka, L. Semeniuk, R. Senecal, T. Senecal, T. Senger, T. Senkow, T. Senner, F. Sepnio, N. Serani, D. Sereda, R. Sereda, N. Sereggela, D. Serfas, D. Sergeant, P. Sergeant, E. Serniak, P. Servello, B. Severight, J. Seward, B. Sey, A. Seyyed Najafi, G. Sgambaro, M. Sgambaro, R. Sgambaro, M. Shad, B. Shah, G. Shah, H. Shah, I. Shah, M. Shah, N. Shah, R. Shah, S. Shah, M. Shahebrahimi, R. Shahrom, S. Shahzad, K. Shakir, K. Shakotko, C. Shank, P. Shankowski, B. Shanmugam, H. Sharif, K. Sharma, R. Sharma, N. Sharp, D. Sharpe, T. Sharpe, T. Shatosky, B. Shaw, D. Shaw, K. Shaw, M. Shaw, R. Shaw, O. Shaykina, K. Shea, R. Shea, C. Shearer, C. Shears, D. Sheaves, L. Sheaves, W. Sheaves, A. Shehata, O. Sheikh, J. Shelfantook, B. Shenton, I. Shepherd, G. Sheppard, J. Sheppard, R. Sheppard, T. Sheppard, A. Shergill, M. Sherman, S. Sherman, I. Sherr, M. Sheth, N. Sheth, D. Shewchuk, J. Shewchuk, L. Shewchuk, L. Shi, A. Shideler, C. Shields, N. Shihinski, S. Shiledarbaxi, K. Shill, A. Shillam, P. Shiner, W. Shipley, J. Shire, V. Shirhatti, G. Shiskin, D. Shivas, E. Shivas, B. Shmoury, B. Shmyr, D. Shmyr, C. Shmyrko, M. Shobeiri, S. Short, D. Shortland, L. Shostak, M. Shukalov, K. Shukla, D. Shular, J. Shumate, S. Shymoniak, J. Shysh, I. Siddhanta, M. Siddiqui, M. Siddon, P. Sideen, M. Sideroff, P. Sidhu, M. Sidney, C. Sieben, J. Sieben, Z. Siegman, R. Sigsworth, W. Sikorski, L. Silas, T. Silbernagel, B. Silue, A. Silva, E. Silva, I. Silva, L. Silva, H. Simani, C. Simard, D. Simard, K. Simard, C. Simcock, J. Simmons, A. Simms, F. Simms, R. Simms, G. Simpkins, D. Simpson, G. Simpson, J. Simpson, P. Simpson, S. Simpson, W. Simpson, E. Sinclair, G. Sinclair, R. Sinclair, S. Sinclair, D. Sine, A. Singh, D. Singh, K. Singh, S. Singh, Y. Singh, M. Singher, S. Singla, M. Sinkova-Hovdestad, A. Sinnett, J. Sisson, J. Sjonnesen, D. Skanderup, W. Skaret, K. Skarra, E. Skarsen, M. Skinner, M. Skipper, G. Skoczek, J. Skog, M. Skolski, R. Skrepnek, S. Skulmoski, M. Skulski, M. Skyrpan, R. Slade, M. Slavin, E. Sleet, K. Slemko, D. Slemp, C. Slessor, J. Sloan, M. Sloan, K. Slotwinski, J. Sloychuk, W. Slunt, S. Slywka, P. Smart, R. Smart, J. Smid, S. Smiegielski, S. Smigelski, B. Smith, C. Smith, D. Smith, E. Smith, F. Smith, G. Smith, J. Smith, K. Smith, L. Smith, M. Smith, R. Smith, S. Smith, T. Smith, C. Smitham, L. Smollet, E. Smolyaninova, A. Smyl, K. Smyl, R. Smyl, B. Smylie, K. Snaden, T. Snell, G. Snider, J. Snider, J. Snow, K. Snow, R. Snow, S. Snow, W. Snow, J. Snowdon, D. Snyder, C. Sohal, D. Sohlbach, D. Sokoloski, J. Soley, V. Sollid, M. Sollows, S. Soloshy, L. Somerville, R. Somji, L. Sommer, B. Song, D. Soni, A. Sonpal, M. Soolagallu, G. Sopczak, H. Sorensen, B. Sorge, L. Soriano, I. Soro, C. Sorochan, D. Soroko, G. Sorwar, M. Soucy, R. Soucy, J. Soulis, L. Soutar, H. Sow, D. Spagrud, D. Spanics, E. Spearman, G. Speer, L. Speer, C. Spencer, D. Spencer, S. Spencer, B. Spendiff, D. Spetz, J. Spetz, K. Spiker, C. Sporidis, J. Springer, M. Sprinkle, A. Spurrell, D. Spurrell, E. Spurrell, R. Spurrell, P. Spurvey, L. Squire, E. St Pierre, R. St. Martin, L. St. Pierre, M. St. Pierre, B. St.Jean, R. St.Pierre, L. Staats, A. Stacey, J. Stacey, I. Stacey-Salmon, G. Stadnichuk, S. Stadnichuk, S. Stadnyk, K. Stagg, M. Stainthorpe, K. Stairs, R. Stamp, R. Stanford, C. Stang, A. Stanley, J. Stanley, C. Stanway, L. Stark, D. Staszewski, S. Stauth, A. Stavropoulos, E. Stearns, M. Stec, D. Steele, R. Steele, L. Steeves, G. Stefan, S. Stefan, N. Stefanyk, W. Steffen, M. Stein, R. Stein, H. Steinbach, J. Steinkey, S. Steinkey, A. Stella, R. Stelten, D. Stemmann, P. Stephen, R. Stephens, T. Stephens, T. Stephenson, B. Stevens, G. Stevens, J. Stevens, L. Stevens, N. Stevens, T. Stevens, H. Stevenson, J. Stevenson, N. Stevenson, R. Stevenson, C. Stevenson-Penton, R. Steward, C. Stewart, D. Stewart, I. Stewart, J. Stewart, K. Stewart, L. Stewart, M. Stewart, R. Stewart, W. Stewart, R. Stieben, M. Stiefel, D. Stinn, S. Stirling, M. Stobart, D. Stobbe, J. Stober, M. Stockes, M. Stockton, S. Stokes, K. Stolz, T. Stolz, J. Storey, M. Storrar, B. Stortz, D. Stout, R. Stoutenberg, S. Strachan, W. Strand, D. Strang, R. Strang, B. Stratichuk, M. Street, S. Street, R. Stretch, R. Striegler, J. Strilchuk, M. Stroh, R. Strong, G. Stroud, K. Struck, R. Struski, J. Struthers, D. Strynadka, L. Stuart, P. Stuart, R. Stuckless, C. Study, J. Stuebing, G. Sturdy, P. Sturgeon, D. Sturrock, A. Styles, M. Styles, P. Su, M. Suarez, V. Subasic, R. Subramaniam, S. Suche, R. Sukkel, J. Sullivan, M. Sullivan, C. Summers, E. Summers, T. Sun, U. Sundaram, C. Surgenor, R. Suriyanarayanan, J. Surrey, G. Surugiu, D. Sutherland, K. Sutherland, L. Sutherland, S. Sutherland, C. Suttie, B. Sutton, S. Sverdahl, T. Svoboda, S. Swain, M. Swan, J. Swannack, J. Swanson, W. Swanson, R. Swarnkar, D. Swartz, R. Sweeney, S. Sweetapple, N. Swennumson, D. Swiegocki, E. Switzer, A. Sychak, K. Sydorko, D. Syed, J. Sykes, T. Sylvester, D. Sylvestre, G. Sylvestre, T. Sypher-Michel, N. Szalay, C. Szmata, C. Szpecht, D. Sztym, K. Szydlik, J. Ta, V. Ta, C. Tacadena, M. Tade, A. Taghipour, A. Taguinod, V. Tai, P. Taiani, D. Tainton, D. Tait, G. Tait, O. Tait, D. Tajiri, D. Takala, G. Talati, S. Talati, D. Talbot, M. Talerico, D. Tallas, B. Talma, K. Tam, N. Taman, B. Tan, C. Tan, K. Tan, M. Tanasescu, E. Tang, L. Tang, X. Tang, G. Tangonan, T. Tanner, M. Tapley, C. Tarache, A. Tarasenco, C. Tardif, C. Tardiff, K. Targett, B. Tarkowski, K. Tarkowski, R. Taron, H. Tarraf, D. Tarrant, J. Tatarin, J. Taubert, N. Tavassoli, A. Taylor, B. Taylor, C. Taylor, G. Taylor, H. Taylor, J. Taylor, K. Taylor, L. Taylor, M. Taylor, N. Taylor, P. Taylor, R. Taylor, S. Taylor, C. Tearoe, J. Teed, M. Teeple, J. Tejada, S. Tejpar, M. Teleptean, B. Temesgen, G. Temple, J. Temple, T. Temple, C. Templeton, K. Tenney, J. Teppin, G. Teske, W. Tetachuk, C. Tetreau, J. Tettensor, B. Tetz, J. Tetz, S. Tetz, F. Thaddaues, L. Thai Mullin, T. Tham, C. Thatcher, S. Thaung Oo, G. Theriault, J. Theriault, M. Theroux, G. Therriault, R. Thibodeau, J. Thiessen, W. Thijs, P. Thimaiah, S. Thind, K. Thistleton, M. Thoen, E. Thomas, I. Thomas, L. Thomas, A. Thompson, C. Thompson, D. Thompson, E. Thompson, H. Thompson, I. Thompson, J. Thompson, K. Thompson, L. Thompson, M. Thompson, R. Thompson, S. Thompson, T. Thompson, C. Thomsen, J. Thomsen, P. Thomsen, A. Thomson, B. Thomson, J. Thomson, K. Thomson, R. Thomson, T. Thomson, J. Thorleifson, D. Thorne, K. Thorne, E. Thornton, K. Thornton, D. Thurman, M. Thyer, S. Tieh, P. Tieu, V. Tiffen, B. Tiffin, G. Tighe, M. Tilford-Shaw, D. Tillapaugh, K. Tillotson, T. Tillotson, R. Timlick, N. Timm, D. Timms, S. Timothy, N. Tindall, M. Tineo, T. Tingey, D. Tipper, B. Tipton, D. Tiwary, R. Tiwary, E. To, B. Tobin, V. Tobin, K. Tobler, B. Todd, C. Todd, S. Toews, D. Tomar, R. Tomiak, C. Tomlinson, D. Tomlinson, L. Tomlinson, A. Tomszak, N. Tomte, M. Tonon, S. Tookey, V. Topacio, S. Topolnitsky, K. Tordon, L. Torrance, P. Torrance, N. Torres, D. Torriero, M. Tosio, L. Tough, D. Toullelan, O. Tozser, C. Tran, R. Trant, L. Trautman, J. Trelinski, W. Trelinski, J. Treliving, E. Tremblay, J. Tremblay, C. Tremblett, D. Trentham, M. Tribiger, J. Trifaux, P. Trifaux, A. Trinh, D. Trinh, H. Trinh, J. Trto, R. Trudel, A. Truefitt, A. Truong, S. Truong, C. Tse, Y. Tse, G. Tsemenko, M. Tsineli, P. Tso, Y. Tu, R. Tucker, C. Tuffs, A. Tuico, D. Tuite, J. Tuite, S. Tulan, B. Tulloch, N. Tulloch, B. Tumbach, T. Turbide, J. Turcotte, T. Turgeon, D. Turnbull, B. Turner, C. Turner, D. Turner, K. Turner, R. Turner, B. Turpin, D. Turpin, V. Turska, S. Turton, S. Tutkaluk, S. Tuttle, I. Tutto, T. Twist, M. Twomey, O. Tyan, A. Tyler, E. Tylosky, L. Tymchuk, W. Tymchuk, D. Tyner, S. Tyrell, G. Tyrer, P. Tyrer, S. Udupa, D. Uduwara Merennage, L. Uhrich, T. Uhrich, E. Ukat, S. Ulloa, E. Ulrich, G. Ulrich, J. Umali, O. Umana, U. Umoh, J. Underdahl, N. Underwood, R. Underwood, T. Ung, K. Unger, L. Unland, B. Unrath, J. Unrau, U. Upadhyaya, C. Upham, D. Urban, J. Urbankowska, L. Urbina, J. Urdaneta, C. Urlacher, A. Ustariz, R. Vachon, S. Vadnai, A. Valentine, G. Valiquette, L. Vallee, M. Vallee, W. Vallee, A. Valmadrid, C. Valois, W. Van den Oever, M. van der Burgh, V. Van Der Merwe, B. van Dyke, N. Van Dyke, P. van Eerde, J. Van Es, L. van Heerden, C. van Niekerk, S. Van Rensburg, C. Van Schoor, C. Vanberg, M. Vanberg, J. Vandeligt, T. Vandemark, M. Vankosky, C. Vare, L. Varela Avendano, M. Varga, D. Varty, A. Vasquez, M. Vasquez-Placid, J. Vasseur, A. Vaughan, N. Vaughan, J. Veale, S. Vekved, B. Velagapudi, M. Velez, B. Velichka, S. Venkatesh, R. Venn, D. Venning, J. Vera, D. Verbicky, N. Veriotes, A. Verma, S. Veroba, J. Verot, N. Vetrici, K. Veysey, J. Vezina, C. Viana, G. Vibert, J. Vicic, S. Vicic, N. Vick, B. Vickery, R. Villanueva, J. Villemaire, P. Villeneuve, R. Vinkle, R. Vinnakota, B. Vinoly, J. Virtanen, B. Virus, G. Virus, K. Virus, M. Virus, C. Visan, A. Visotto, D. Vitali, N. Vizcuna Alvarado, M. Vogan, A. Volk, R. Volkmann, J. Vollman, M. Vollman, W. Volschenk, E. von Hertzberg, L. Vondermuhll, B. Von-Grat, A. Voth, A. Votta, A. Vredegoor, J. Vrolson, J. Vuong, Q. Vuong, B. Vye, G. Wack, E. Waddell, K. Waddell, C. Wadden, K. Waddy, J. Wade, T. Waggoner, T. Wagil, C. Wagner, D. Wagner, G. Wagner, J. Wagner, K. Wagner, M. Wahl, D. Wakaruk, A. Walchuk, D. Waldner, D. Waldo, A. Walintschek, D. Walker, G. Walker, H. Walker, J. Walker, T. Walker, K. Walko, D. Wall, B. Wallace, C. Wallace, D. Wallace, E. Wallace, H. Wallace, K. Wallace, T. Walle, G. Wallin, M. Wallis, V. Wallwork, A. Walsh, B. Walsh, P. Walsh, R. Walsh, S. Walsh, T. Walsh, L. Walter, A. Walters, C. Walters, K. Walters, S. Walton, D. Wanchuk, C. Wang, H. Wang, J. Wang, L. Wang, R. Wang, S. Wang, T. Wang, W. Wang, X. Wang, B. Wangler, D. Wannas, T. Warburton, D. Ward, E. Ward, K. Ward, W. Warholik, C. Wark, W. Warman, F. Warraich, G. Warren, J. Warren, R. Warren, C. Wasylciw, L. Wasylciw, L. Watchorn, J. Waterfield, M. Waterfield, J. Watkins, B. Watson, C. Watson, D. Watson, E. Watson, G. Watson, J. Watson, K. Watson, S. Watson, C. Watt, D. Watt, G. Watt, J. Watts, S. Wayte, D. Weatherby, C. Weatherhead, H. Weaver, L. Weaving, A. Webb, B. Webb, G. Webb, P. Webb, D. Webber, J. Webber, D. Weber, J. Webster, K. Webster, D. Weed, M. Weekes, E. Weening, E. Weenink, B. Wei, Z. Wei, J. Weibrecht, J. Weigl, J. Weik, D. Weimer, C. Weingarten, J. Weir, R. Weir, G. Weisbeck, R. Weisbrot, M. Weishaar, C. Weiss, D. Weiss, M. Weiss, D. Welch, M. Welland, T. Welland, B. Wellman, C. Wells, D. Wells, R. Wells, K. Wellwood, J. Welsh, L. Welsh, W. Welte, G. Welwood, Z. Wen, G. Weng, P. Wenger, M. Wenner, K. Wenzel, D. Werle, C. Werner, H. Werner, C. Werstiuk, N. Wert, B. Weslake, D. West, M. Westad, D. Westbrook, R. Westbrook, K. Westland, R. Westland, B. Wetthuhn, N. Whalen, D. Wheating, L. Wheating, C. Wheaton, J. Wheaton, A. Wheeler, N. Wheeler, S. Wheeler, C. Whelan, M. Whelan, R. Whelan, R. Whelan-Maloney, G. Whelen, M. Whelen, S. Whelen, J. Whidden, B. White, F. White, J. White, M. White, N. White, R. White, D. Whitehouse, S. Whiteley, A. Whiteside, C. Whitford, H. Whitmore, M. Whittaker, A. Whitten, H. Whitten, H. Whynot, R. Whyte, A. Wickins, C. Wickwire, D. Wiebe, M. Wiebe, T. Wiebe, D. Wiege, J. Wieler, D. Wiens, S. Wiens, C. Wietzel, Z. Wigglesworth, S. Wight, D. Wijesingha, M. Wilcox, B. Wild, R. Wild, D. Wilde, L. Wilde, M. Wilders, J. Wilding, D. Wiles, J. Wilhelm, C. Wilk, T. Wilk, C. Wilkes, M. Wilkie, C. Wilkin, D. Wilkins, K. Wilkinson, G. Will, P. Will, E. Willard, B. Williams, C. Williams, D. Williams, G. Williams, L. Williams, M. Williams, N. Williams, R. Williams, S. Williams, T. Williams, W. Williams, A. Williamson, C. Williamson, D. Williamson, K. Williamson, M. Williamson, J. Willick, B. Willis, M. Willis, R. Willis, D. Willms, S. Wills, C. Willson, D. Willson, C. Wilson, D. Wilson, G. Wilson, J. Wilson, M. Wilson, R. Wilson, W. Wilson, A. Wilson-O'Coffey, J. Wilton, L. Wilyman, A. Winfield, A. Wingert, J. Winia, B. Winiarz, J. Winquist, R. Winslow, C. Winsor, J. Winsor, A. Winter, G. Winters, R. Winters, G. Wirachowsky, J. Wirachowsky, R. Wirtanen, P. Wiseman, I. Wishart, M. Witmer, Z. Witt, D. Wittman, C. Wlad, A. Wocknitz, K. Woidak, D. Woitas, T. Woitte, R. Wojtowicz, D. Wold, S. Wolf, C. Woloshyn, J. Wolstenholme, B. Wolstoncroft, J. Wolter, R. Wolters, A. Wong, J. Wong, L. Wong, N. Wong, C. Woo, J. Woo, K. Woo, L. Woo, L. Wood, P. Wood, R. Wood, S. Wood, M. Woodfin, F. Woodford, T. Woodford, A. Woodger, D. Woods, J. Woods, M. Woods, S. Woods, T. Woods, M. Woodske, J. Wooldridge, S. Woolfitt, R. Woolner, K. Wormington, C. Worthman, S. Wosnack, H. Wossey Ogandaga Mbourou, R. Wourms, B. Wright, C. Wright, L. Wright, M. Wright, R. Wright, S. Wright, G. Wrinn, T. Wruth, B. Wu, J. Wu, M. Wu, B. Wurzer, J. Wurzer, K. Wutzke, B. Wychopen, G. Wyndham, D. Wyshynski, L. Wysocki, Y. Xia, Y. Xie, H. Xu, J. Xu, Q. Xu, Y. Xu, Z. Xu, D. Yackel, K. Yakimowich, L. Yakiwchuk, C. Yang, D. Yang, J. Yang, L. Yang, X. Yang, M. Yanota, H. Yare, A. Yaremko, K. Yaremko, R. Yarmuch, J. Yaroslawsky, S. Yasin, B. Yates, B. Yeboue, B. Yee, G. Yee, C. Yeoman, D. Yep, P. Yepes, J. Yeske, J. Yip, K. Yip, L. Yip, L. Yogasundaram, Y. Yohanna, F. Yohannes, D. York, F. York, A. Yoshikawa, D. Youck, B. Young, C. Young, D. Young, K. Young, L. Young, M. Young, N. Young, P. Young, V. Young, K. Yousaf, R. Yowney, M. Yu, P. Yuan, C. Yuen, D. Yuill, J. Yuill, R. Yuristy, R. Zabek, A. Zacharias, T. Zachoda, C. Zackowski, J. Zaderey, N. Zaderey, E. Zahacy, D. Zahara, K. Zahara, B. Zaitsoff, S. Zakeri, G. Zambrano, D. Zambrano Suarez, C. Zaparyniuk, D. Zarowny, K. Zarowny, K. Zayac, T. Zeiser, D. Zelman, B. Zeng, A. Zenide, W. Zeniuk, G. Zeran, J. Zerpa, K. Zerr, M. Zerr, S. Zgurski, J. Zhang, M. Zhang, Q. Zhang, W. Zhang, X. Zhang, Y. Zhang, B. Zhao, C. Zhao, L. Zhao, T. Zhao, M. Zhekov, G. Zheng, S. Zheng, Z. Zheng, S. Zhong, H. Zhou, Q. Zhou, X. Zhou, L. Zhu, W. Zhu, E. Zhuromsky, S. Ziadeh, B. Ziegler, D. Zilinski, E. Zilinski, E. Zimmer, M. Zisi, J. Zizek, C. Zoller, L. Zseder, G. Zubiak, M. Zubkow, A. Zubot, J. Zuk, N. Zukiwski, J. Zur, J. Zwolak.

YEAR-END RESERVES

DETERMINATION OF RESERVES

For the year ended December 31, 2014 the Company retained Independent Qualified Reserves Evaluators, Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. Sproule evaluated the Company's North America and International crude oil, bitumen, natural gas and NGL reserves. GLJ evaluated the Company's Horizon synthetic crude oil reserves. The Evaluators conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the Evaluators as to the Company's reserves. All reserve values are Company Gross unless stated otherwise.

CORPORATE TOTAL

- Proved crude oil, SCO, bitumen and NGL reserves increased 2% to 4.51 billion barrels. Proved natural gas reserves increased 39% to 6.00 Tcf. Total proved reserves increased 7% to 5.51 billion BOE.
- Proved plus probable crude oil, SCO, bitumen and NGL reserves increased 8% to 7.54 billion barrels. Proved plus probable natural gas reserves increased 33% to 8.14 Tcf. Total proved plus probable reserves increased 11% to 8.89 billion BOE.
- Proved reserve additions and revisions, including acquisitions, were 282 million barrels of crude oil, SCO, bitumen and NGL and 2,264 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio was 230%. The total proved BOE reserve life index is 19.0 years.
- Proved plus probable reserve additions and revisions, including acquisitions, were 753 million barrels of crude oil, bitumen, SCO and NGL and 2,597 billion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 413%. The total proved plus probable BOE reserve life index is 30.6 years.
- Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 27% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 5% of the corporate total proved reserves.

NORTH AMERICA EXPLORATION AND PRODUCTION

- Proved crude oil, bitumen and NGL reserves increased 9% to 2.05 billion barrels. Proved natural gas reserves increased 41% to 5.87 Tcf. Total proved BOE increased 18% to 3.03 billion barrels.
- Proved plus probable crude oil, bitumen and NGL reserves increased 9% to 3.49 billion barrels. Proved plus probable natural gas reserves increased 35% to 7.93 Tcf. Total proved plus probable BOE increased 15% to 4.81 billion barrels.
- Proved reserve additions and revisions, including acquisitions, were 308 million barrels of crude oil, bitumen and NGL and 2,266 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio is 292%. The total proved BOE reserve life index in 13.1 years.
- Proved plus probable reserve additions and revisions, including acquisitions, were 420 million barrels of crude oil, bitumen and NGL and 2,602 billion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 363%. The total proved plus probable BOE reserve life index is 20.7 years.
- Proved undeveloped crude oil, bitumen and NGL reserves accounted for 36% of the North America total proved reserves and proved undeveloped natural gas reserves accounted for 9% of the North America total proved reserves.
- Thermal oil sands ("bitumen") proved reserves increased 5% to 1.22 billion barrels primarily due new proved undeveloped additions at Primrose and Wolf Lake. Proved reserve additions and revisions were 99 million barrels. Total proved plus probable bitumen reserves increased 7% to 2.31 billion barrels.

NORTH AMERICA OIL SANDS MINING AND UPGRADING

- Proved plus probable SCO reserves increased 9% to 3.59 billion barrels, primarily due to a revised mine plan allowing mining to Total Volume : Bitumen In Place ("TV:BIP") of 13 versus 12 in the original plan.

INTERNATIONAL EXPLORATION AND PRODUCTION

- North Sea proved reserves decreased 9% to 218 million BOE. North Sea proved plus probable reserves decreased 5% to 327 million BOE.
- Offshore Africa proved reserves decreased 4% to 104 million BOE primarily due to production. Offshore Africa proved plus probable reserves decreased 3% to 165 million BOE.

SUMMARY OF COMPANY GROSS RESERVES

As of December 31, 2014
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	114	125	233	371	1,969	3,907	96	3,559
Developed Non-Producing	5	22	2	–	–	256	5	77
Undeveloped	26	82	39	846	189	1,706	87	1,553
Total Proved	145	229	274	1,217	2,158	5,869	188	5,189
Probable	58	88	121	1,095	1,435	2,057	70	3,210
Total Proved plus Probable	203	317	395	2,312	3,593	7,926	258	8,399
North Sea								
Proved								
Developed Producing	28					60		38
Developed Non-Producing	10					5		11
Undeveloped	166					18		169
Total Proved	204					83		218
Probable	104					31		109
Total Proved plus Probable	308					114		327
Offshore Africa								
Proved								
Developed Producing	24					32		29
Developed Non-Producing	–					–		–
Undeveloped	72					17		75
Total Proved	96					49		104
Probable	53					49		61
Total Proved plus Probable	149					98		165
Total Company								
Proved								
Developed Producing	166	125	233	371	1,969	3,999	96	3,626
Developed Non-Producing	15	22	2	–	–	261	5	88
Undeveloped	264	82	39	846	189	1,741	87	1,797
Total Proved	445	229	274	1,217	2,158	6,001	188	5,511
Probable	215	88	121	1,095	1,435	2,137	70	3,380
Total Proved plus Probable	660	317	395	2,312	3,593	8,138	258	8,891

SUMMARY OF COMPANY NET RESERVES

As of December 31, 2014
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	99	105	176	281	1,609	3,436	71	2,913
Developed Non-Producing	4	18	1	–	–	215	4	63
Undeveloped	23	69	29	668	155	1,403	68	1,246
Total Proved	126	192	206	949	1,764	5,054	143	4,222
Probable	48	69	82	838	1,139	1,737	53	2,519
Total Proved plus Probable	174	261	288	1,787	2,903	6,791	196	6,741
North Sea								
Proved								
Developed Producing	28					60		38
Developed Non-Producing	10					5		11
Undeveloped	166					18		169
Total Proved	204					83		218
Probable	104					31		109
Total Proved plus Probable	308					114		327
Offshore Africa								
Proved								
Developed Producing	21					23		25
Developed Non-Producing	–					–		–
Undeveloped	57					13		59
Total Proved	78					36		84
Probable	41					32		46
Total Proved plus Probable	119					68		130
Total Company								
Proved								
Developed Producing	148	105	176	281	1,609	3,519	71	2,976
Developed Non-Producing	14	18	1	–	–	220	4	74
Undeveloped	246	69	29	668	155	1,434	68	1,474
Total Proved	408	192	206	949	1,764	5,173	143	4,524
Probable	193	69	82	838	1,139	1,800	53	2,674
Total Proved plus Probable	601	261	288	1,787	2,903	6,973	196	7,198

RECONCILIATION OF COMPANY GROSS RESERVES

As of December 31, 2014
Forecast Prices and Costs

PROVED	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2013	117	244	258	1,157	2,211	4,160	110	4,790
Discoveries	1	–	–	–	–	14	1	5
Extensions	7	29	–	91	–	121	5	152
Infill Drilling	3	12	–	–	–	562	32	141
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	31	–	–	–	–	1,407	34	300
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(1)	(1)	–	–	(4)	(52)	(1)	(16)
Technical Revisions	7	(3)	34	8	(9)	215	20	94
Production	(19)	(52)	(18)	(39)	(40)	(557)	(13)	(276)
December 31, 2014	**145**	**229**	**274**	**1,217**	**2,158**	**5,869**	**188**	**5,189**
North Sea								
December 31, 2013	224					91		239
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(16)					(6)		(17)
Technical Revisions	1					1		2
Production	(6)					(3)		(7)
December 31, 2014	**204**					**83**		**218**
Offshore Africa								
December 31, 2013	99					54		108
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					–		–
Technical Revisions	1					3		1
Production	(4)					(8)		(5)
December 31, 2014	**96**					**49**		**104**
Total Company								
December 31, 2013	440	244	258	1,157	2,211	4,305	110	5,137
Discoveries	1	–	–	–	–	14	1	5
Extensions	7	29	–	91	–	121	5	152
Infill Drilling	4	12	–	–	–	562	32	142
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	31	–	–	–	–	1,407	34	300
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(17)	(1)	–	–	(4)	(58)	(1)	(33)
Technical Revisions	9	(3)	34	8	(9)	219	20	97
Production	(29)	(52)	(18)	(39)	(40)	(568)	(13)	(288)
December 31, 2014	**445**	**229**	**274**	**1,217**	**2,158**	**6,001**	**188**	**5,511**

RECONCILIATION OF COMPANY GROSS RESERVES

As of December 31, 2014
Forecast Prices and Costs

PROBABLE	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2013	49	90	104	1,013	1,078	1,721	64	2,685
Discoveries	1	–	–	–	–	3	–	1
Extensions	5	12	–	43	358	57	3	431
Infill Drilling	3	4	1	–	–	179	11	49
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	9	–	–	–	–	485	13	103
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	–	–	–	–	(7)	6	–	(5)
Technical Revisions	(9)	(18)	16	39	6	(394)	(21)	(54)
Production	–	–	–	–	–	–	–	–
December 31, 2014	**58**	**88**	**121**	**1,095**	**1,435**	**2,057**	**70**	**3,210**
North Sea								
December 31, 2013	101					34		107
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	13					2		13
Technical Revisions	(10)					(5)		(11)
Production	–					–		–
December 31, 2014	**104**					**31**		**109**
Offshore Africa								
December 31, 2013	54					49		62
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	1					1		1
Technical Revisions	(2)					(1)		(2)
Production	–					–		–
December 31, 2014	**53**					**49**		**61**
Total Company								
December 31, 2013	204	90	104	1,013	1,078	1,804	64	2,854
Discoveries	1	–	–	–	–	3	–	1
Extensions	5	12	–	43	358	57	3	431
Infill Drilling	3	4	1	–	–	179	11	49
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	9	–	–	–	–	485	13	103
Dispositions	–	–	–	–	–	–	–	–
Economic Factors	14	–	–	–	(7)	9	–	9
Technical Revisions	(21)	(18)	16	39	6	(400)	(21)	(67)
Production	–	–	–	–	–	–	–	–
December 31, 2014	**215**	**88**	**121**	**1,095**	**1,435**	**2,137**	**70**	**3,380**

RECONCILIATION OF COMPANY GROSS RESERVES

As of December 31, 2014
Forecast Prices and Costs

PROVED PLUS PROBABLE	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
December 31, 2013	166	334	362	2,170	3,289	5,881	174	7,475
Discoveries	2	–	–	–	–	17	1	6
Extensions	12	41	–	134	358	178	8	583
Infill Drilling	6	16	1	–	–	741	43	190
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	40	–	–	–	–	1,892	47	403
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(1)	(1)	–	–	(11)	(46)	(1)	(21)
Technical Revisions	(2)	(21)	50	47	(3)	(179)	(1)	40
Production	(19)	(52)	(18)	(39)	(40)	(557)	(13)	(276)
December 31, 2014	**203**	**317**	**395**	**2,312**	**3,593**	**7,926**	**258**	**8,399**
North Sea								
December 31, 2013	325					125		346
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	1					–		1
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(3)					(4)		(4)
Technical Revisions	(9)					(4)		(9)
Production	(6)					(3)		(7)
December 31, 2014	**308**					**114**		**327**
Offshore Africa								
December 31, 2013	153					103		170
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	1					1		1
Technical Revisions	(1)					2		(1)
Production	(4)					(8)		(5)
December 31, 2014	**149**					**98**		**165**
Total Company								
December 31, 2013	644	334	362	2,170	3,289	6,109	174	7,991
Discoveries	2	–	–	–	–	17	1	6
Extensions	12	41	–	134	358	178	8	583
Infill Drilling	7	16	1	–	–	741	43	191
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	40	–	–	–	–	1,892	47	403
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(3)	(1)	–	–	(11)	(49)	(1)	(24)
Technical Revisions	(12)	(21)	50	47	(3)	(181)	(1)	30
Production	(29)	(52)	(18)	(39)	(40)	(568)	(13)	(288)
December 31, 2014	**660**	**317**	**395**	**2,312**	**3,593**	**8,138**	**258**	**8,891**

NOTES REFERRING TO RESERVES TABLES:

(1) Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
(2) Company Net reserves are working interest share after deduction of royalties and including any royalty interests.
(3) BOE values may not calculate due to rounding.
(4) Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2015	2016	2017	2018	2019	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	65.00	80.00	90.00	91.35	92.72	1.50%
Western Canada Select (C$/bbl)	60.50	75.13	84.52	85.79	87.07	1.50%
Canadian Light Sweet (C$/bbl)	70.35	87.36	98.28	99.75	101.25	1.50%
Edmonton Pentanes+ (C$/bbl)	78.60	97.60	109.80	111.44	113.12	1.50%
North Sea Brent (US$/bbl)	68.00	83.00	93.00	94.40	95.81	1.50%
Natural gas						
AECO (C$/MMBtu)	3.32	3.71	3.90	4.47	5.05	1.50%
BC Westcoast Station 2 (C$/MMBtu)	3.27	3.66	3.85	4.42	5.00	1.50%
Henry Hub Louisiana (US$/MMBtu)	3.25	3.75	4.00	4.50	5.00	1.50%

A foreign exchange rate of 0.8500 US$/C$ for 2015 and 0.8700 US$/C$ after 2015 was used in the 2014 evaluation.

(5) Reserve additions and revisions are comprised of all categories of Company Gross reserve changes, exclusive of production.
(6) Reserve replacement ratio is the Company Gross reserve additions and revisions divided by the Company Gross production in the same period.
(7) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
(8) Reserve Life Index is based on the amount for the relevant reserve category divided by the 2015 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.

RESOURCE DISCLOSURE (1)

Horizon Oil Sands Synthetic Crude Oil

Discovered Bitumen Initially-in-place		14,400	million barrels
Proved Company Gross Reserves	2,158 million barrels of SCO		
Bitumen volume associated with Proved SCO reserves		2,540	million barrels of Bitumen
Probable Company Gross Reserves	1,435 million barrels of SCO		
Bitumen volume associated with Probable SCO reserves		1,593	million barrels of Bitumen
Best Estimate Contingent Resources other than Reserves		3,693	million barrels of Bitumen
Bitumen Produced to Date		236	million barrels
Unrecoverable portion of Discovered Bitumen Initially-in-place (2)		6,338	million barrels

Bitumen (Thermal Oil)

Discovered Bitumen Initially-in-place	96,627	million barrels
Proved Company Gross Reserves	1,217	million barrels of Bitumen
Probable Company Gross Reserves	1,095	million barrels of Bitumen
Best Estimate Contingent Resources other than Reserves	8,491	million barrels of Bitumen
Bitumen Produced to Date	445	million barrels
Unrecoverable portion of Discovered Bitumen Initially-in-place (2)	85,380	million barrels

Pelican Lake Heavy Crude Oil Pool

Discovered Heavy Crude Oil Initially-in-place	4,100	million barrels
Proved Company Gross Reserves	274	million barrels of Heavy Crude Oil
Probable Company Gross Reserves	121	million barrels of Heavy Crude Oil
Best Estimate Contingent Resources other than Reserves	153	million barrels of Heavy Crude Oil
Heavy Crude Oil Produced to Date	215	million barrels
Unrecoverable portion of Discovered Heavy Crude Oil Initially-in-place (2)	3,337	million barrels

(1) All volumes are Company Gross.
(2) A portion may be recoverable with the development of new technology.

Note: Company gross proved and proved plus probable reserves at December 31, 2014.
Produced to Date is cumulative production to December 31, 2014.
Contingent Resources at December 31, 2014.

CAPITAL AND FREE CASH FLOW PRICING ASSUMPTIONS

1. 2015F reflects capital spending of $6.0 billion and the midpoint of guidance as of January 12th, 2015, and strip pricing as of February 2015.
2. 2016F to 2017F capital is targeted between $8.0 and $8.75 billion and less thereafter.
3. 2014 based upon actual; WTI of US$92.92/bbl, AECO of C$4.19/GJ, WCS differential of 21% and foreign exchange of US$1.00 to C$1.10.
4. 2015F based upon the midpoint of guidance as of January 12th, 2015, and pricing assumptions at February 2015; WTI of US$54.99/bbl, AECO of C$2.95/GJ, WCS differential of 27% and foreign exchange of US$1.00 to C$1.26.
5. 2016F to 2020F based on constant price assumptions of:

	$70.00 WTI	Strip	$90.00 WTI
WTI (US$)	$ 70.00	$ 81.00	$ 90.00
NYMEX (US$/MMbtu)	$ 3.75	$ 3.74	$ 4.48
AECO (C$/GJ)	$ 3.50	$ 3.45	$ 4.00
WCS differential	22%	22%	22%
FX (1 US$ = X C$)	$ 1.176	$ 1.126	$ 1.11

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, and the "Outlook" section of this MD&A, particularly in reference to the 2015 guidance provided with respect to production and budgeted capital expenditures, also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available. For additional information, refer to the "Risks and Uncertainties" section of this MD&A.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings from operations, cash flow from operations, adjusted cash production costs and net asset value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Net Earnings and Cash Flow from Operations" section of this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2014.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's consolidated financial statements and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil.

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's 2014 financial results compared to 2013 and 2012, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2015. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2014, its Annual Information Form for the year ended December 31, 2014, and its audited consolidated financial statements for the year ended December 31, 2014 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 4, 2015.

DEFINITIONS AND ABBREVIATIONS

AECO	Alberta natural gas reference location
AIF	Annual Information Form
API	specific gravity measured in degrees on the American Petroleum Institute scale
ARO	asset retirement obligations
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
BOE	barrels of oil equivalent
BOE/d	barrels of oil equivalent per day
Bitumen	solid or semi-solid viscous mixture consisting mainly of pentanes and heavier hydrocarbons with viscosity greater than 10,000 centipoise
Brent	Dated Brent
C$	Canadian dollars
CAGR	compound annual growth rate
CAPEX	capital expenditures
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalents
Crude oil	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and synthetic crude oil
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offloading Vessel
GHG	greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Horizon	Horizon Oil Sands
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LNG	liquefied natural gas
Mbbl	thousand barrels
Mbbl/d	thousand barrels per day
MBOE	thousand barrels of oil equivalent
MBOE/d	thousand barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
MMbbl	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British thermal units
MMcf	million cubic feet
MMcf/d	million cubic feet per day
MMcfe	millions of cubic feet equivalent
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
PRT	Petroleum Revenue Tax
SAGD	Steam-Assisted Gravity Drainage
SCO	synthetic crude oil
SEC	United States Securities and Exchange Commission
Tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US GAAP	generally accepted accounting principles in the United States
US$	United States dollars
WCS	Western Canadian Select
WCS Heavy Differential	WCS Heavy Differential from WTI
WTI	West Texas Intermediate reference location at Cushing, Oklahoma

OBJECTIVES AND STRATEGY

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value (1) on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments while transitioning to a long life, low decline asset base. The Company takes a balanced approach to growth and investments and focuses on creating long-term shareholder value. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, Pelican Lake heavy crude oil (2), primary heavy crude oil, bitumen (thermal oil), SCO and natural gas;
- A large, balanced, diversified, high quality asset base;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and a strong financial position.

(1) Discounted value of crude oil and natural gas reserves plus value of unproved land, less net debt.
(2) Pelican Lake heavy crude oil is 14–17º API oil, which receives medium quality crude netbacks due to lower production costs and lower royalty rates.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Supporting and participating in pipeline expansions and/or new additions; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil and bitumen (thermal oil).

Operational discipline, safe, effective and efficient operations as well as cost control are fundamental to the Company. By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in its properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to complete its growth projects. Additionally, the Company's risk management hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt financing to selectively acquire properties generating future cash flows in its core areas.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)			**2014**		2013		2012
Product sales		**$**	**21,301**	$	17,945	$	16,195
Net earnings		**$**	**3,929**	$	2,270	$	1,892
Per common share	– basic	**$**	**3.60**	$	2.08	$	1.72
	– diluted	**$**	**3.58**	$	2.08	$	1.72
Adjusted net earnings from operations (1)		**$**	**3,811**	$	2,435	$	1,618
Per common share	– basic	**$**	**3.49**	$	2.24	$	1.48
	– diluted	**$**	**3.47**	$	2.23	$	1.47
Cash flow from operations (2)		**$**	**9,587**	$	7,477	$	6,013
Per common share	– basic	**$**	**8.78**	$	6.87	$	5.48
	– diluted	**$**	**8.74**	$	6.86	$	5.47
Dividends declared per common share (3)		**$**	**0.90**	$	0.575	$	0.42
Total assets		**$**	**60,200**	$	51,754	$	48,980
Total long-term liabilities		**$**	**26,167**	$	20,748	$	20,721
Capital expenditures, net of dispositions		**$**	**11,744**	$	7,274	$	6,308

(1) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings from Operations" presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Cash Flow from Operations" presents certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

(3) On March 5, 2014, the Board of Directors approved a quarterly dividend of $0.225 per common share, beginning with the dividend payable on April 1, 2014. In 2013, the Board of Directors approved a dividend of $0.20 per common share on November 5, 2013, beginning with the dividend payable on January 1, 2014 ($0.125 per common share, approved on March 6, 2013, beginning with the dividend payable on April 1, 2013). In 2012, the Board of Directors approved a quarterly dividend of $0.105 per common share, beginning with the dividend payable on April 1, 2012.

Adjusted Net Earnings from Operations

($ millions)		**2014**		2013		2012
Net earnings as reported	**$**	**3,929**	$	2,270	$	1,892
Share-based compensation expense (recovery), net of tax (1)		**66**		135		(214)
Unrealized risk management (gain) loss, net of tax (2)		**(339)**		32		(37)
Unrealized foreign exchange loss, net of tax (3)		**256**		226		129
Realized foreign exchange loss (gain) on repayment of US dollar debt securities, net of tax (4)		**36**		(12)		(210)
Gain on corporate acquisitions/disposition of properties, net of tax (5)		**(137)**		(231)		–
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (6)		**–**		15		58
Adjusted net earnings from operations	**$**	**3,811**	$	2,435	$	1,618

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings or are capitalized to Oil Sands Mining and Upgrading construction costs.

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil and natural gas.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings.

(4) During 2014, the Company repaid US$500 million of 1.45% notes and US$350 million of 4.90% notes. During 2013, the Company repaid US$400 million of 5.15% notes. During 2012, the Company repaid US$350 million of 5.45% notes.

(5) During 2014, the Company recorded an after-tax gain of $137 million related to the acquisition of certain producing crude oil and natural gas properties. During 2013, the Company recorded an after-tax gain of $231 million related to the acquisition of Barrick Energy Inc. and the disposition of a 50% interest in an exploration right in South Africa.

(6) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. During 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013, resulting in an increase in the Company's deferred income tax liability of $15 million. During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax rate relief on UK North Sea decommissioning expenditures to 50%, resulting in an increase in the Company's deferred income tax liability of $58 million.

Cash Flow from Operations

($ millions)		**2014**		2013		2012
Net earnings	**$**	**3,929**	$	2,270	$	1,892
Non-cash items:						
Depletion, depreciation and amortization		**4,880**		4,844		4,328
Share-based compensation		**66**		135		(214)
Asset retirement obligation accretion		**193**		171		151
Unrealized risk management (gain) loss		**(451)**		39		(42)
Unrealized foreign exchange loss		**256**		226		129
Realized foreign exchange loss (gain) on repayment of US dollar debt securities		**36**		(12)		(210)
Equity loss from investment		**8**		4		9
Deferred income tax expense (recovery)		**807**		31		(30)
Gain on corporate acquisitions/disposition of properties		**(137)**		(289)		–
Current income tax on disposition of properties		**–**		58		–
Cash flow from operations	**$**	**9,587**	$	7,477	$	6,013

For 2014, the Company reported net earnings of $3,929 million compared with net earnings of $2,270 million for 2013 (2012 – $1,892 million). Net earnings for 2014 included net after-tax income of $118 million related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses and gains on repayments of long-term debt, gains on corporate acquisitions/disposition of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities (2013 – $165 million after-tax expenses; 2012 – $274 million after-tax income). Excluding these items, adjusted net earnings from operations for 2014 were $3,811 million compared with $2,435 million for 2013 (2012 – $1,618 million).

The increase in adjusted net earnings for 2014 from the comparable period in 2013 was primarily due to:

- higher crude oil and NGLs, natural gas, and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments;
- higher crude oil and NGLs and natural gas netbacks in the North America segment;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar;

partially offset by:

- lower crude oil sales volumes in the Offshore Africa segment; and
- lower crude oil netbacks in the North Sea and Offshore Africa segments.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings and are discussed in detail in the relevant sections of this MD&A.

Cash flow from operations for 2014 increased to $9,587 million ($8.78 per common share) from $7,477 million for 2013 ($6.87 per common share) (2012 – $6,013 million; $5.48 per common share). The increase in cash flow from operations for 2014 from 2013 was primarily due to the factors noted above relating to the increase in adjusted net earnings, together with the impact of lower cash taxes.

In the Company's Exploration and Production activities, the 2014 average sales price per bbl of crude oil and NGLs increased 4% to average $77.04 per bbl from $73.81 per bbl in 2013 (2012 – $72.44 per bbl), and the 2014 average natural gas price increased 35% to average $4.83 per Mcf from $3.58 per Mcf in 2013 (2012 – $2.70 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2014 sales price of SCO averaged $100.27 per bbl, compared with $100.75 per bbl in 2013 (2012 – $90.74 per bbl).

Total production of crude oil and NGLs before royalties increased 11% to 531,194 bbl/d from 478,240 bbl/d in 2013 (2012 – 451,378 bbl/d). The increase in crude oil and NGLs production from 2013 was due to higher production in the North America segment and strong and reliable production in Horizon.

Total natural gas production before royalties increased 34% to average 1,555 MMcf/d from 1,158 MMcf/d in 2013 (2012 – 1,220 MMcf/d). The increase in natural gas production was primarily a result of the acquisitions of producing Canadian natural gas properties in 2014, and the completion of the Septimus drilling program and plant facility expansion in 2013.

Total crude oil and NGLs and natural gas production volumes before royalties increased 18% to average 790,410 BOE/d from 671,162 BOE/d in 2013 (2012 – 654,665 BOE/d).

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

($ millions, except per common share amounts)

2014	**Total**	**Dec 31**	**Sep 30**	**Jun 30**	**Mar 31**
Product sales	**$ 21,301**	**$ 4,850**	**$ 5,370**	**$ 6,113**	**$ 4,968**
Net earnings	**$ 3,929**	**$ 1,198**	**$ 1,039**	**$ 1,070**	**$ 622**
Net earnings per common share					
– basic	**$ 3.60**	**$ 1.10**	**$ 0.95**	**$ 0.98**	**$ 0.57**
– diluted	**$ 3.58**	**$ 1.09**	**$ 0.94**	**$ 0.97**	**$ 0.57**

2013	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales	$ 17,945	$ 4,330	$ 5,284	$ 4,230	$ 4,101
Net earnings	$ 2,270	$ 413	$ 1,168	$ 476	$ 213
Net earnings per common share					
– basic	$ 2.08	$ 0.38	$ 1.07	$ 0.44	$ 0.19
– diluted	$ 2.08	$ 0.38	$ 1.07	$ 0.44	$ 0.19

Volatility in the quarterly net earnings over the eight most recently completed quarters was primarily due to:

- Crude oil pricing – The impact of fluctuating demand, inventory storage levels, increased shale oil production in North America, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from WTI in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- Natural gas pricing – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US.
- Crude oil and NGLs sales volumes – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the strong heavy crude oil drilling program, the impact and timing of acquisitions, and the impact of turnarounds at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- Natural gas sales volumes – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to pricing and the impact and timing of acquisitions.
- Production expense – Fluctuations primarily due to the impact of the demand for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations in North America, the impact and timing of acquisitions, and turnarounds at Horizon.
- Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in depletion, depreciation and amortization expense in the North Sea resulting from the planned early cessation of production at the Murchison platform, and the impact of turnarounds at Horizon.
- Share-based compensation – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- Risk management – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- Foreign exchange rates – Changes in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- Income tax expense – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- Gains on corporate acquisitions/disposition of properties – Fluctuations due to the recognition of gains on corporate acquisitions/dispositions in the fourth quarter of 2014 and the third quarter of 2013.

BUSINESS ENVIRONMENT

(Yearly average)		2014		2013		2012
WTI benchmark price (US$/bbl)	**$**	**92.92**	$	98.00	$	94.19
Dated Brent benchmark price (US$/bbl)	**$**	**98.85**	$	108.62	$	111.56
WCS blend differential from WTI (US$/bbl)	**$**	**19.41**	$	25.11	$	21.05
WCS blend differential from WTI (%)		**21%**		26%		22%
SCO price (US$/bbl)	**$**	**91.35**	$	98.18	$	92.59
Condensate benchmark price (US$/bbl)	**$**	**92.84**	$	101.67	$	100.92
NYMEX benchmark price (US$/MMBtu)	**$**	**4.37**	$	3.67	$	2.80
AECO benchmark price (C$/GJ)	**$**	**4.19**	$	3.00	$	2.28
US / Canadian dollar average exchange rate (US$)	**$**	**0.9054**	$	0.9710	$	1.0004
US / Canadian dollar year end exchange rate (US$)	**$**	**0.8620**	$	0.9402	$	1.0051

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are also highly sensitive to fluctuations in foreign exchange rates. Realized prices in 2014 were impacted by the weaker Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil and natural gas sales as realized pricing is based on US dollar denominated benchmarks. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2014, with a high of approximately US$0.94 in January 2014 and a low of approximately US$0.86 in December 2014.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. For 2014, WTI averaged US$92.92 per bbl, a decrease of 5% from US$98.00 per bbl for 2013 (2012 – US$94.19 per bbl).

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$98.85 per bbl for 2014, a decrease of 9% from US$108.62 per bbl for 2013 (2012 – US$111.56 per bbl).

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply in the world market contributed to a significant decrease in crude oil benchmark pricing in the fourth quarter of 2014. The Organization of the Petroleum Exporting Countries' ("OPEC") decision in November 2014 to not reduce crude oil production to offset the excess world supply continues to put downward pressure on benchmark pricing. In January 2015, WTI averaged US$47.33 per bbl and Brent averaged US$48.07 per bbl and in February, WTI averaged US$50.72 per bbl and Brent averaged US$57.93 per bbl. The Brent differential from WTI tightened for 2014 from 2013 due to continued debottlenecking of logistical constraints from Cushing to the US Gulf Coast in the first half of 2014.

The WCS Heavy Differential averaged 21% for 2014 compared with 26% for 2013 (2012 – 22%). The WCS Heavy Differential tightened from the comparable period in 2013 as the comparable period in 2013 reflected lower heavy oil demand due to unplanned refinery disruptions and pipeline logistical constraints. In January 2015, the WCS Heavy Differential averaged US$16.90 per bbl or 36% and in February 2015, the WCS Heavy Differential averaged US$14.20 per bbl or 28%. To partially mitigate its exposure to fluctuating heavy crude oil differentials, the Company entered into 30,000 bbl/d of crude oil WCS differential swaps for the first quarter of 2015 at weighted average fixed WCS differential of US$21.49 per bbl.

The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$91.35 per bbl in 2014, a decrease of 7% from US$98.18 per bbl for 2013 (2012 – US$92.59 per bbl). The decrease in SCO pricing was primarily due to a decrease in WTI benchmark pricing.

NYMEX natural gas prices averaged US$4.37 per MMBtu for 2014, an increase of 19% from US$3.67 per MMBtu for 2013 (2012 – US$2.80 per MMBtu). AECO natural gas pricing averaged $4.19 per GJ for 2014, an increase of 40% from $3.00 per GJ for 2013 (2012 – $2.28 per GJ). The higher natural gas pricing in 2014 was primarily due to the drawdown of natural gas storage inventories as a result of the colder than normal winter temperatures in the first quarter of 2014. Growing US shale gas production resulted in natural gas inventories returning to normal industry levels by the end of 2014, leading to downward pressure on prices.

ANALYSIS OF CHANGES IN PRODUCT SALES

($ millions)	2012	Changes due to Volumes	Changes due to Prices	Changes due to Other	2013	**Changes due to Volumes**	**Changes due to Prices**	**Changes due to Other**	**2014**
North America									
Crude oil and NGLs	$ 10,480	$ 501	$ 319	$ (54)	$ 11,246	**$ 1,527**	**$ 585**	**$ (26)**	**$ 13,332**
Natural gas	1,127	(67)	353	–	1,413	**497**	**721**	**–**	**2,631**
	11,607	434	672	(54)	12,659	**2,024**	**1,306**	**(26)**	**15,963**
North Sea									
Crude oil and NGLs	924	(121)	4	(12)	795	**(3)**	**(37)**	**(73)**	**682**
Natural gas	4	4	2	–	10	**8**	**1**	**–**	**19**
	928	(117)	6	(12)	805	**5**	**(36)**	**(73)**	**701**
Offshore Africa									
Crude oil and NGLs	699	38	(7)	3	733	**(264)**	**(52)**	**(7)**	**410**
Natural gas	74	15	2	–	91	**(10)**	**12**	**–**	**93**
	773	53	(5)	3	824	**(274)**	**(40)**	**(7)**	**503**
Subtotal									
Crude oil and NGLs	12,103	418	316	(63)	12,774	**1,260**	**496**	**(106)**	**14,424**
Natural gas	1,205	(48)	357	–	1,514	**495**	**734**	**–**	**2,743**
	13,308	370	673	(63)	14,288	**1,755**	**1,230**	**(106)**	**17,167**
Oil Sands Mining and Upgrading	2,871	399	361	–	3,631	**463**	**(20)**	**21**	**4,095**
Midstream	93	–	–	17	110	**–**	**–**	**10**	**120**
Intersegment eliminations and other (1)	(77)	–	–	(7)	(84)	**–**	**–**	**3**	**(81)**
Total	$ 16,195	$ 769	$ 1,034	$ (53)	$ 17,945	**$ 2,218**	**$ 1,210**	**$ (72)**	**$ 21,301**

(1) Eliminates internal transportation, electricity charges, and natural gas sales.

Product sales increased 19% to $21,301 million for 2014 from $17,945 million for 2013 (2012 – $16,195 million). The increase was primarily due to higher crude oil and NGLs, natural gas, and SCO sales volumes in the North America and Oil Sands Mining and Upgrading segments and an increase in realized North America crude oil and NGLs and natural gas prices.

For 2014, 6% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2013 – 9%; 2012 – 11%). North Sea accounted for 3% of crude oil and NGLs and natural gas product sales for 2014 (2013 – 4%; 2012 – 6%), and Offshore Africa accounted for 3% of crude oil and NGLs and natural gas product sales for 2014 (2013 – 5%; 2012 – 5%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2014	2013	2012
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**390,814**	343,699	326,829
North America – Oil Sands Mining and Upgrading (1)	**110,571**	100,284	86,077
North Sea	**17,380**	18,334	19,824
Offshore Africa	**12,429**	15,923	18,648
	531,194	478,240	451,378
Natural gas (MMcf/d)			
North America	**1,527**	1,130	1,198
North Sea	**7**	4	2
Offshore Africa	**21**	24	20
	1,555	1,158	1,220
Total barrels of oil equivalent (BOE/d)	**790,410**	671,162	654,665
Product mix			
Light and medium crude oil and NGLs	**15%**	15%	16%
Pelican Lake heavy crude oil	**6%**	7%	6%
Primary heavy crude oil	**18%**	20%	19%
Bitumen (thermal oil)	**14%**	14%	15%
Synthetic crude oil (1)	**14%**	15%	13%
Natural gas	**33%**	29%	31%
Percentage of gross revenue (1) (2)			
(excluding Midstream revenue)			
Crude oil and NGLs	**85%**	90%	91%
Natural gas	**15%**	10%	9%

(1) The Company commenced production of diesel for internal use at Horizon in the third quarter of 2014. 2014 SCO production before royalties excludes 545 bbl/d of SCO consumed internally as diesel.
(2) Net of blending costs and excluding risk management activities.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2014	2013	2012
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**318,291**	287,428	273,374
North America – Oil Sands Mining and Upgrading (1)	**104,095**	95,098	82,171
North Sea	**17,313**	18,279	19,772
Offshore Africa	**11,500**	12,973	13,628
	451,199	413,778	388,945
Natural gas (MMcf/d)			
North America	**1,407**	1,080	1,171
North Sea	**7**	4	2
Offshore Africa	**18**	20	17
	1,432	1,104	1,190
Total barrels of oil equivalent (BOE/d)	**689,893**	597,835	587,246

(1) The Company commenced production of diesel for internal use at Horizon in the third quarter of 2014. 2014 SCO production before royalties excludes 545 bbl/d of SCO consumed internally as diesel.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Total 2014 production averaged 790,410 BOE/d, an 18% increase from 671,162 BOE/d in 2013 (2012 – 654,665 BOE/d).

Total production of crude oil and NGLs before royalties increased 11% to 531,194 bbl/d for 2014 from 478,240 bbl/d in 2013 (2012 – 451,378 bbl/d). The increase in crude oil and NGLs production from 2013 was primarily due to higher production in the North America segment and strong and reliable production in Horizon. Crude oil and NGLs production for 2014 was within the Company's previously issued guidance of 531,000 to 557,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 33% of the Company's total production in 2014 on a BOE basis. Total natural gas production before royalties increased 34% to 1,555 MMcf/d for 2014 from 1,158 MMcf/d for 2013 (2012 – 1,220 MMcf/d). The increase in natural gas production from 2013 was primarily a result of the acquisitions of producing Canadian natural gas properties in 2014, and the completion of the Septimus drilling program and plant facility expansion. Natural gas production for 2014 was within the Company's previously issued guidance of 1,550 to 1,570 MMcf/d.

NORTH AMERICA – EXPLORATION AND PRODUCTION

North America crude oil and NGLs production for 2014 increased 14% to average 390,814 bbl/d from 343,699 bbl/d for 2013 (2012 – 326,829 bbl/d). The increase in production from 2013 was primarily due to increased production related to the acquisitions of producing Canadian crude oil properties in 2014, production at the Company's thermal areas including Kirby South, the impact of the heavy crude oil drilling program, and the ramp up of production at Pelican Lake.

North America natural gas production for 2014 increased 35% to average 1,527 MMcf/d from 1,130 MMcf/d in 2013 (2012 – 1,198 MMcf/d). The increase in natural gas production from 2013 was primarily a result of the acquisitions of producing Canadian natural gas properties in 2014, and the completion of the Septimus drilling program and plant facility expansion.

NORTH AMERICA – OIL SANDS MINING AND UPGRADING

Production for 2014 increased 10% to average 110,571 bbl/d compared with 100,284 bbl/d for 2013 (2012 – 86,077 bbl/d). Production in 2014 increased from 2013 due to increased plant reliability and the successful completion of the coker plant expansion in 2014.

NORTH SEA

North Sea crude oil production for 2014 was 17,380 bbl/d, a decrease of 5% from 18,334 bbl/d for 2013 (2012 – 19,824 bbl/d). Production in 2014 reflected the impact of reinstatement of production from the Banff FPSO in July 2014, which had been offline since December 2011 after suffering storm damage. Production in 2014 also reflected the cessation of production due to the planned early decommissioning of the Murchison platform which commenced in 2013, unplanned downtime on the Tiffany platform, and natural field declines.

OFFSHORE AFRICA

Offshore Africa crude oil production for 2014 decreased 22% to 12,429 bbl/d from 15,923 bbl/d for 2013 (2012 – 18,648 bbl/d) primarily due to natural field declines.

CORPORATE PRODUCTION GUIDANCE FOR 2015

The Company targets production levels in 2015 to average between 562,000 bbl/d and 602,000 bbl/d of crude oil and NGLs and between 1,730 MMcf/d and 1,770 MMcf/d of natural gas.

CRUDE OIL INVENTORY VOLUMES

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized on crude oil volumes that were stored in various tanks, pipelines, or FPSOs, as follows:

(bbl)	**2014**	2013	2012
North America – Exploration and Production	**930,116**	830,673	643,758
North America – Oil Sands Mining and Upgrading (SCO)	**1,266,063**	1,550,857	993,627
North Sea	**368,808**	385,073	77,018
Offshore Africa	**461,997**	185,476	1,036,509
	3,026,984	2,952,079	2,750,912

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

		2014		2013		2012
Crude oil and NGLs ($/bbl) (1)						
Sales price (2)	$	**77.04**	$	73.81	$	72.44
Transportation		**2.41**		2.22		2.20
Realized sales price, net of transportation		**74.63**		71.59		70.24
Royalties		**12.99**		11.13		10.67
Production expense		**18.25**		17.14		16.11
Netback	$	**43.39**	$	43.32	$	43.46
Natural gas ($/Mcf) (1)						
Sales price (2)	$	**4.83**	$	3.58	$	2.70
Transportation		**0.27**		0.28		0.26
Realized sales price, net of transportation		**4.56**		3.30		2.44
Royalties		**0.38**		0.18		0.09
Production expense		**1.48**		1.42		1.31
Netback	$	**2.70**	$	1.70	$	1.04
Barrels of oil equivalent ($/BOE) (1)						
Sales price (2)	$	**58.48**	$	56.46	$	52.85
Transportation		**2.18**		2.10		2.04
Realized sales price, net of transportation		**56.30**		54.36		50.81
Royalties		**8.90**		7.74		7.07
Production expense		**14.67**		14.24		13.14
Netback	$	**32.73**	$	32.38	$	30.60

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

ANALYSIS OF PRODUCT PRICES – EXPLORATION AND PRODUCTION

		2014		2013		2012
Crude oil and NGLs ($/bbl) (1) (2)						
North America	$	**75.09**	$	69.90	$	67.93
North Sea	$	**106.63**	$	112.46	$	111.90
Offshore Africa	$	**97.81**	$	110.21	$	111.18
Company average	$	**77.04**	$	73.81	$	72.44
Natural gas ($/Mcf) (1) (2)						
North America	$	**4.72**	$	3.43	$	2.57
North Sea	$	**7.07**	$	5.69	$	5.14
Offshore Africa	$	**11.98**	$	10.45	$	10.31
Company average	$	**4.83**	$	3.58	$	2.70
Company average ($/BOE) (1) (2)	$	**58.48**	$	56.46	$	52.85

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

Realized crude oil and NGLs prices increased 4% to average $77.04 per bbl for 2014 from $73.81 per bbl for 2013 (2012 – $72.44 per bbl). The increase in 2014 was primarily due to tightening WCS Heavy Differentials and the impact of a weakening Canadian dollar, partially offset by lower benchmark pricing.

The Company's realized natural gas price increased 35% to average $4.83 per Mcf for 2014 from $3.58 per Mcf for 2013 (2012 – $2.70 per Mcf). The increase in 2014 was due to the drawdown of natural gas storage inventories as a result of colder than normal winter temperatures in 2014.

NORTH AMERICA

North America realized crude oil prices increased 7% to average $75.09 per bbl for 2014 from $69.90 per bbl for 2013 (2012 – $67.93 per bbl), primarily due to tightening WCS Heavy Differentials and the impact of a weakening Canadian dollar, partially offset by lower WTI benchmark pricing.

North America realized natural gas prices increased 38% to average $4.72 per Mcf for 2014 from $3.43 per Mcf for 2013 (2012 – $2.57 per Mcf), due to the drawdown of natural gas storage inventories as a result of colder than normal winter temperatures in the first quarter of 2014.

The Company continues to focus on its crude oil marketing strategy including a blending strategy that expands markets within current pipeline infrastructure, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with refiners to add incremental heavy crude oil and bitumen (thermal oil) conversion capacity. During 2014, the Company contributed approximately 167,000 bbl/d of heavy crude oil blends to the WCS stream. During 2013, the Company entered into a 20 year transportation agreement to ship 80,000 bbl/d of crude oil on the proposed Energy East pipeline originating at Hardisty, Alberta with delivery points in Quebec City, Quebec and Saint John, New Brunswick. This pipeline is subject to regulatory approval. The Company previously entered into a 20 year transportation agreement to ship 75,000 bbl/d of crude oil on the proposed Kinder Morgan Trans Mountain Expansion from Edmonton, Alberta to Vancouver, British Columbia. This pipeline is subject to regulatory approval. The Company has entered into a 20 year transportation agreement to ship 120,000 bbl/d of heavy crude oil on the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast. In addition, the Company also entered into a 20 year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy crude oil to a major US refiner. The construction of the Keystone XL Pipeline is dependent on a Presidential Permit.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Yearly average)		**2014**		2013		2012
Wellhead Price (1) (2)						
Light and medium crude oil and NGLs (C$/bbl)	**$**	**76.94**	$	76.44	$	72.20
Pelican Lake heavy crude oil (C$/bbl)	**$**	**77.58**	$	70.62	$	68.84
Primary heavy crude oil (C$/bbl)	**$**	**76.29**	$	69.06	$	66.64
Bitumen (thermal oil) (C$/bbl)	**$**	**70.78**	$	66.14	$	66.46
Natural gas (C$/Mcf)	**$**	**4.72**	$	3.43	$	2.57

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

NORTH SEA

North Sea realized crude oil prices decreased 5% to average $106.63 per bbl for 2014 from $112.46 per bbl for 2013 (2012 – $111.90 per bbl). Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

OFFSHORE AFRICA

Offshore Africa realized crude oil prices decreased 11% to average $97.81 per bbl for 2014 from $110.21 per bbl for 2013 (2012 – $111.18 per bbl). Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

		2014		2013		2012
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**13.74**	$	11.30	$	10.33
North Sea	**$**	**0.33**	$	0.33	$	0.29
Offshore Africa	**$**	**6.83**	$	18.18	$	29.46
Company average	**$**	**12.99**	$	11.13	$	10.67
Natural gas ($/Mcf) (1)						
North America	**$**	**0.36**	$	0.14	$	0.06
Offshore Africa	**$**	**1.74**	$	1.83	$	1.77
Company average	**$**	**0.38**	$	0.18	$	0.09
Company average ($/BOE) (1)	**$**	**8.90**	$	7.74	$	7.07

(1) Amounts expressed on a per unit basis are based on sales volumes.

NORTH AMERICA

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less operating, capital and abandonment costs incurred ("net profit").

Crude oil and NGLs royalties averaged approximately 19% of product sales for 2014 compared with 17% in 2013 (2012 – 16%) primarily due to higher realized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 11.5% to 13.5% of product sales for 2015.

Natural gas royalties averaged approximately 8% of product sales for 2014 compared with 5% in 2013 (2012 – 3%) primarily due to higher realized natural gas prices. North America natural gas royalties per Mcf are anticipated to average 3% to 4% of product sales for 2015.

NORTH SEA

The UK government royalties on crude oil were eliminated effective January 1, 2003. The remaining royalty is a gross overriding royalty on the Ninian field.

OFFSHORE AFRICA

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 8% for 2014 compared with 17% for 2013 (2012 – 26%) primarily due to lower realized crude oil prices in 2014 and adjustments to royalties on liftings in 2013. Offshore Africa royalty rates are anticipated to average 3.5% to 5.5% of product sales for 2015.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

		2014		2013		2012
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**14.98**	$	14.20	$	13.40
North Sea	**$**	**74.04**	$	66.19	$	53.53
Offshore Africa	**$**	**43.97**	$	25.32	$	23.11
Company average	**$**	**18.25**	$	17.14	$	16.11
Natural gas ($/Mcf) (1)						
North America	**$**	**1.42**	$	1.39	$	1.28
North Sea	**$**	**9.10**	$	4.67	$	3.75
Offshore Africa	**$**	**3.22**	$	2.53	$	2.27
Company average	**$**	**1.48**	$	1.42	$	1.31
Company average ($/BOE) (1)	**$**	**14.67**	$	14.24	$	13.14

(1) Amounts expressed on a per unit basis are based on sales volumes.

NORTH AMERICA

North America crude oil and NGLs production expense for 2014 increased 5% to $14.98 per bbl from $14.20 per bbl for 2013 (2012 – $13.40 per bbl). The increase in production expense was primarily due to higher trucking and fuel costs across the heavy crude oil and thermal areas, together with higher servicing costs related to heavy crude oil production. North America crude oil and NGLs production expense is anticipated to average $12.50 to $14.50 per bbl for 2015.

North America natural gas production expense for 2014 increased 2% to $1.42 per Mcf from $1.39 per Mcf for 2013 (2012 – $1.28 per Mcf). Natural gas production expense increased from 2013 due to the acquisitions of producing Canadian natural gas properties in 2014 that had higher production expense per Mcf than the Company's existing properties. The production expense on the acquired assets has continued to decline as expected as they have become fully integrated into the Company's operations. North America natural gas production expense is anticipated to average $1.30 to $1.40 per Mcf for 2015.

NORTH SEA

North Sea crude oil production expense for 2014 increased 12% to $74.04 per bbl from $66.19 per bbl for 2013 (2012 – $53.53 per bbl). Production expense increased due to natural field declines on relatively fixed cost structure, the impact of the unplanned downtime on the Tiffany platform, and a weaker Canadian dollar. North Sea crude oil production expense is anticipated to average $48.00 to $52.00 per bbl for 2015 as the Banff FPSO has returned to the field and production has been reinstated.

OFFSHORE AFRICA

Offshore Africa crude oil production expense for 2014 increased 74% to $43.97 per bbl from $25.32 per bbl for 2013 (2012 – $23.11 per bbl). The increase in production expense from 2013 primarily reflects the impact of natural field declines on relatively fixed cost structure, the timing of liftings from various fields, which have different cost structures, a weaker Canadian dollar, and the impact of product inventory valuation adjustments in Olowi, Gabon in 2014. Offshore Africa crude oil production expense is anticipated to average $30.00 to $34.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2014**		2013		2012
North America	**$**	**3,901**	$	3,568	$	3,413
North Sea		**269**		552		296
Offshore Africa		**105**		134		165
Expense	**$**	**4,275**	$	4,254	$	3,874
$/BOE (1)	**$**	**17.27**	$	20.38	$	18.65

(1) Amounts expressed on a per unit basis are based on sales volumes.

Depletion, depreciation and amortization expense for 2014 decreased 15% to $17.27 per BOE from $20.38 per BOE for 2013 (2012 – $18.65 per BOE) due to the impact of lower depletion, depreciation and amortization expense in the North Sea resulting from the planned early cessation of production at the Murchison field in 2013, as well as the impact of increased production on component depreciation determined on a straight-line.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)		**2014**		2013		2012
North America	**$**	**98**	$	92	$	85
North Sea		**38**		35		27
Offshore Africa		**10**		10		7
Expense	**$**	**146**	$	137	$	119
$/BOE (1)	**$**	**0.59**	$	0.66	$	0.57

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense decreased 11% to $0.59 per BOE from $0.66 per BOE for 2013 (2012 – $0.57 per BOE) primarily due to the impact of increased sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During 2014, operating performance continued to be strong, leading to average production of 110,571 bbl/d.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

($/bbl) (1)		**2014**		2013		2012
SCO sales price	**$**	**100.27**	$	100.75	$	90.74
Bitumen value for royalty purposes (2)	**$**	**67.63**	$	65.48	$	59.93
Bitumen royalties (3)	**$**	**5.77**	$	5.11	$	4.34
Transportation	**$**	**1.85**	$	1.57	$	1.83

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.
(2) Calculated as the quarterly average of the bitumen valuation methodology price.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices for 2014 was comparable with 2013 (2012 – $90.74 per bbl), reflecting lower benchmark pricing, offset by the impact of a weakening Canadian dollar.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 20 to the Company's consolidated financial statements.

($ millions)		**2014**		2013		2012
Cash production costs	**$**	**1,609**	$	1,567	$	1,504
Less: costs incurred during turnaround periods		**(98)**		(104)		(154)
Adjusted cash production costs	**$**	**1,511**	$	1,463	$	1,350
Adjusted cash production costs, excluding natural gas costs	**$**	**1,395**	$	1,359	$	1,254
Adjusted natural gas costs		**116**		104		96
Adjusted cash production costs	**$**	**1,511**	$	1,463	$	1,350

($/bbl) (1)		**2014**		2013		2012
Adjusted cash production costs, excluding natural gas costs	**$**	**34.33**	$	37.68	$	39.79
Adjusted natural gas costs		**2.85**		2.89		3.04
Adjusted cash production costs	**$**	**37.18**	$	40.57	$	42.83
Sales (bbl/d) (2)		**111,351**		98,757		86,153

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Sales volumes include turnaround periods.

Adjusted cash production costs averaged $37.18 per bbl for 2014, a decrease of 8% compared with $40.57 per bbl for 2013 (2012 – $42.83 per bbl). The decrease in 2014 adjusted cash production costs reflected increased plant capacity and reliability and the corresponding impact of higher production volumes on a relatively fixed cost structure, excluding the turnaround periods. Adjusted cash production costs are anticipated to average $32.00 to $35.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		**2014**		2013		2012
Depletion, depreciation and amortization	**$**	**596**	$	582	$	447
Less: depreciation incurred during turnaround periods		**(28)**		(79)		(6)
Adjusted depletion, depreciation and amortization	**$**	**568**	$	503	$	441
$/bbl (1)	**$**	**13.97**	$	13.95	$	13.99

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

Adjusted depletion, depreciation and amortization expense on a per bbl basis for 2014 was comparable with 2013 (2012 – $13.99 per bbl).

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		2014		2013		2012
Expense	**$**	**47**	$	34	$	32
$/bbl (1)	**$**	**1.16**	$	0.94	$	1.01

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

MIDSTREAM

($ millions)		2014		2013		2012
Revenue	**$**	**120**	$	110	$	93
Production expense		**34**		34		29
Midstream cash flow		**86**		76		64
Depreciation		**9**		8		7
Equity loss from investment		**8**		4		9
Segment earnings before taxes	**$**	**69**	$	64	$	48

The Company's Midstream assets include three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 85% of the Company's heavy crude oil production is transported to international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The Midstream pipeline assets allow the Company to control the transport of a portion of its own production volumes as well as earn third party revenue. This transportation control enhances the Company's ability to manage the full range of costs associated with the development and marketing of its heavier crude oil.

The Company has a 50% interest in the North West Redwater Partnership ("Redwater Partnership"). Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, in order to provide financing for Project completion based on the current revised Project cost estimate of approximately $8,500 million, the Company, along with APMC, each committed to provide additional funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2014, the Company and APMC each provided $113 million of subordinated debt. Subsequent to December 31, 2014, the Company and APMC each provided an additional $112 million of subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During 2014, Redwater Partnership executed a $3,500 million syndicated credit facility with a group of financial institutions maturing June 2018 and repaid and cancelled its $1,200 million credit facility previously in place. As at December 31, 2014, Redwater Partnership had borrowings of $913 million under the syndicated credit facility.

In addition, during 2014, Redwater Partnership issued $500 million of 3.20% series A senior secured bonds due July 2024 and $500 million of 4.05% series B senior secured bonds due July 2044. Subsequent to December 31, 2014, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)		**2014**		2013		2012
Expense	**$**	**367**	$	335	$	270
$/BOE (1)	**$**	**1.28**	$	1.37	$	1.13

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense for 2014 decreased 7% to $1.28 per BOE from $1.37 per BOE for 2013 (2012 – $1.13 per BOE) primarily due to the impact of higher sales volumes.

SHARE-BASED COMPENSATION

($ millions)		**2014**		2013		2012
Expense (Recovery)	**$**	**66**	$	135	$	(214)

The Company's stock option plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The share-based compensation liability at December 31, 2014 reflected the Company's liability for awards granted to employees at fair value estimated using the Black-Scholes valuation model. In periods when substantial share price changes occur, the Company's net earnings are subject to significant volatility. The Company utilizes its share-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

The Company recorded a $66 million share-based compensation expense for 2014, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the year, and changes in the Company's share price. During 2014, the Company capitalized $14 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (2013 – $25 million costs; 2012 – $12 million recovery).

During 2014, the Company paid $8 million for stock options surrendered for cash settlement (2013 – $4 million; 2012 – $7 million).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)		**2014**		2013		2012
Expense, gross	**$**	**527**	$	454	$	462
Less: capitalized interest		**204**		175		98
Expense, net	**$**	**323**	$	279	$	364
$/BOE (1)	**$**	**1.12**	$	1.14	$	1.52
Average effective interest rate		**3.9%**		4.4%		4.8%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for 2014 increased from 2013 primarily due to the impact of higher overall debt levels. Capitalized interest of $204 million for 2014 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for 2014 decreased from 2013 due to the repayment of higher interest rate US dollar debt securities, the issuance of lower interest rate US dollar debt securities, and an increase in the utilization of the lower cost US commercial paper program that was implemented in 2013.

Net interest and other financing expense for 2014 decreased 2% to $1.12 per BOE from $1.14 per BOE for 2013 (2012 – $1.52 per BOE) primarily due to the impact of increased sales volumes.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

($ millions)		**2014**		2013		2012
Crude oil and NGLs financial instruments	**$**	**(284)**	$	44	$	65
Natural gas financial instruments		**34**		–		–
Foreign currency contracts		**(99)**		(160)		97
Realized (gain) loss	**$**	**(349)**	$	(116)	$	162
Crude oil and NGLs financial instruments	**$**	**(427)**	$	17	$	3
Natural gas financial instruments		**(3)**		3		–
Foreign currency contracts		**(21)**		19		(45)
Unrealized (gain) loss	**$**	**(451)**	$	39	$	(42)
Net (gain) loss	**$**	**(800)**	$	(77)	$	120

During 2014, net realized risk management gains and losses were related to the settlement of crude oil, natural gas and foreign currency contracts. The Company recorded a net unrealized gain of $451 million ($339 million after-tax) on its risk management activities (2013 – $39 million unrealized loss, $32 million after-tax; 2012 – $42 million unrealized gain, $37 million after-tax), primarily related to changes in the fair value of these contracts.

The cash settlement amount of commodity and foreign currency derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices and foreign exchange rates at the time of final settlement, as compared to their fair value at December 31, 2014.

Complete details related to outstanding derivative financial instruments at December 31, 2014 are disclosed in note 17 to the Company's consolidated financial statements.

FOREIGN EXCHANGE

($ millions)		**2014**		2013		2012
Net realized loss (gain)	**$**	**47**	$	(16)	$	(178)
Net unrealized loss (1)		**256**		226		129
Net loss (gain)	**$**	**303**	$	210	$	(49)

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. Predominantly all of the Company's revenue is based on reference to US dollar benchmark prices. An increase in the value of the Canadian dollar in relation to the US dollar results in decreased revenue from the sale of the Company's production. Conversely a decrease in the value of the Canadian dollar in relation to the US dollar results in increased revenue from the sale of the Company's production. Production expenses in the North Sea are subject to foreign currency fluctuations due to changes in the exchange rate of the UK pound sterling to the US and Canadian dollars. Production expenses in Offshore Africa are subject to foreign currency fluctuations due to changes in the exchange rate of the US dollar to the Canadian dollar. The value of the Company's US dollar denominated debt is also impacted by the value of the Canadian dollar in relation to the US dollar.

The net realized foreign exchange loss for 2014 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$500 million of 1.45% notes and US$350 million of 4.90% notes. The net unrealized foreign exchange loss in 2014 was primarily related to the impact of a weaker Canadian dollar with respect to remaining US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$500 million of 1.45% notes and US$350 million of 4.90% notes. Included in the net unrealized loss for 2014 was an unrealized gain of $259 million (2013 – $165 million unrealized gain, 2012 – $53 million unrealized loss) related to the impact of cross currency swaps. The US/Canadian dollar exchange rate at December 31, 2014 was US$0.8620 (December 31, 2013 – US$0.9402; December 31, 2012 – US$1.0051).

INCOME TAXES

($ millions, except income tax rates)		2014		2013		2012
North America [(1)]	$	**702**	$	544	$	366
North Sea		**(68)**		23		115
Offshore Africa [(2)]		**43**		202		206
PRT (recovery) expense – North Sea		**(273)**		(56)		44
Other taxes		**23**		22		16
Current income tax expense		**427**		735		747
Deferred income tax expense		**681**		163		–
Deferred PRT expense (recovery) – North Sea		**126**		(132)		(30)
Deferred income tax expense (recovery)		**807**		31		(30)
		1,234		766		717
Income tax rate and other legislative changes		**–**		(15)		(58)
	$	**1,234**	$	751	$	659
Effective income tax rate on adjusted net earnings from operations [(3)]		**24.6%**		26.2%		27.8%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.
(2) Includes current income taxes relating to disposition of properties in 2013.
(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The current PRT recovery in the North Sea in 2014 included the impact of amendments to tax filings for prior years.

During 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

During 2014, the Company filed Scientific Research and Experimental Development claims of approximately $450 million (2013 – $390 million; 2012 – $300 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

For 2015, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax expense of $300 million to $400 million in Canada and recoveries of $190 million to $220 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)		2014		2013		2012
Exploration and Evaluation						
Net expenditures (proceeds) [2] [3]	**$**	**1,190**	$	(144)	$	309
Property, Plant and Equipment						
Net property acquisitions [2]		**2,893**		246		144
Well drilling, completion and equipping		**2,162**		2,140		1,902
Production and related facilities		**1,830**		1,878		1,978
Capitalized interest and other [4]		**106**		120		111
Net expenditures		**6,991**		4,384		4,135
Total Exploration and Production		**8,181**		4,240		4,444
Oil Sands Mining and Upgrading						
Horizon Phases 2/3 construction costs		**2,502**		2,057		1,315
Sustaining capital		**352**		278		223
Turnaround costs		**29**		100		21
Capitalized interest and other [4]		**227**		157		51
Total Oil Sands Mining and Upgrading		**3,110**		2,592		1,610
Midstream		**62**		197		14
Abandonments [5]		**346**		207		204
Head office		**45**		38		36
Total net capital expenditures	**$**	**11,744**	$	7,274	$	6,308
By segment						
North America [2]	**$**	**7,500**	$	4,026	$	4,126
North Sea		**400**		334		254
Offshore Africa [3]		**281**		(120)		64
Oil Sands Mining and Upgrading		**3,110**		2,592		1,610
Midstream		**62**		197		14
Abandonments [5]		**346**		207		204
Head office		**45**		38		36
Total	**$**	**11,744**	$	7,274	$	6,308

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's disposition of a 50% interest in its exploration right in South Africa in 2013.
(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(5) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2014 were $11,744 million compared with $7,274 million for 2013 (2012 – $6,308 million). The increase in 2014 capital expenditures from 2013 was primarily due to the acquisition of Canadian crude oil and natural gas properties in 2014.

On April 1, 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties, including exploration and evaluation assets of $823 million, for cash consideration of $3,110 million, subject to final closing adjustments. During 2014, the Company also acquired a number of additional producing crude oil and natural gas properties in the North American Exploration and Production segment for net cash consideration of $643 million, resulting in a non-cash gain of $137 million.

During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in an after-tax gain on sale of exploration and evaluation property of $166 million. In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

Included in the Company's original 2015 budget was approximately $2,000 million of capital flexibility, which allows the Company to reallocate capital over 2015 as required. In response to declining commodity prices, in December 2014 the Company proactively reviewed its capital allocation strategy and in January 2015 announced that it would access this capital flexibility to reduce capital spending by approximately $2,400 million. Subsequently, capital expenditure guidance for 2015 has been further reduced by $150 million as a result of the reduction in scope of the originally planned 2015 Horizon maintenance turnaround from 35 days to 6 days. The Company has significant additional capital flexibility in 2015 to further curtail capital spending if required or increase capital spending if commodity prices strengthen. For additional details, refer to the "Outlook" section of this MD&A.

Drilling Activity (number of wells)	**2014**	2013	2012
Net successful natural gas wells	**75**	44	35
Net successful crude oil wells [(1)]	**1,023**	1,117	1,203
Dry wells	**19**	30	33
Stratigraphic test / service wells	**437**	384	727
Total	**1,554**	1,575	1,998
Success rate (excluding stratigraphic test / service wells)	**98%**	97%	97%

(1) Includes bitumen wells.

NORTH AMERICA

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 66% of the total capital expenditures for 2014 compared to approximately 59% for 2013 (2012 – 69%).

During 2014, the Company targeted 76 net natural gas wells, including 28 wells in Northeast British Columbia, 38 wells in Northwest Alberta and 10 wells in Northern Plains. The Company also targeted 1,036 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 896 primary heavy crude oil wells, 24 Pelican Lake heavy crude oil wells, 15 bitumen (thermal oil) wells and 5 light crude oil wells were drilled. Another 96 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company continued to access its large crude oil drilling inventory to maximize value in both the short and long term. Due to the Company's focus on drilling crude oil wells in recent years, natural gas drilling activities have been reduced from historical levels. Deferred natural gas well locations have been retained in the Company's prospect inventory.

During 2013, the Company discovered bitumen emulsion at surface in areas of the Primrose field. The Company continues to work with the regulator on the causation review of the bitumen emulsion seepage. The Company's near-term steaming plan at Primrose has been modified, with steaming being reduced in certain areas.

Overall thermal oil production for 2014 averaged approximately 107,800 bbl/d, compared with approximately 96,500 bbl/d in 2013 (2012 – 99,500 bbl/d). Production volumes reflected the cyclic nature of thermal oil production at Primrose and production at Kirby South.

In response to declining commodity prices, in January 2015 the Company deferred development activities in the Kirby North Project.

Development of the tertiary recovery conversion projects at Pelican Lake continued and 24 horizontal wells were drilled during 2014. Pelican Lake production averaged approximately 50,100 bbl/d in 2014 (2013 – 42,900; 2012 – 38,200 bbl/d).

In order to expand its pipeline infrastructure the Company has participated in the expansion of the Cold Lake pipeline system. Initial pipeline commissioning activities are expected to commence in the first quarter of 2015 with the final phases of the project expected to continue for approximately three years.

OIL SANDS MINING AND UPGRADING

Phase 2/3 expansion activity in 2014 was focused on field construction of the gas recovery unit, sulphur recovery unit, butane treatment unit, coker expansion, hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, cooling water tower, tailings, hydrotransport, froth treatment, tailings transfer pumphouses and pipelines, extraction plants, and ore preparation plant civil works along with engineering and procurement related to the ore preparation plants, froth treatment plant, hydrotransport, sourwater concentrator and combined hydrotreater.

Budgeted capital spending in 2015 has been revised from $2,450 million to $2,200 million through targeted cost efficiencies, while maintaining planned expansion activities.

NORTH SEA

During 2014, the Company completed a five gross well drilling program at the Ninian field, supported by the Brownfield Allowance program. Subsequent to December 31, 2014, the Company reduced its 2015 drilling program to one well and suspended all other development activities. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

OFFSHORE AFRICA

During 2014, in Côte d'Ivoire, the Company contracted a drilling rig for a 10 gross well development program at the Espoir field. Subsequent to December 31, 2014, the Company drilled the first well with first oil anticipated at the end of the first quarter of 2015. At the Baobab field, during 2014, the Company secured a drilling rig and subsequent to December 31, 2014, the rig arrived on location. The Company has commenced drilling the first well of its six gross well program with first oil anticipated in the second quarter of 2015.

In Côte d'Ivoire, during 2014, the operator in Block CI-514 completed drilling an exploratory well and encountered the presence of light oil. The well was plugged and the data gathered will now be evaluated to determine the extent of the accumulation and the forward plan for appraisal. The operator anticipates drilling a second exploratory well in the second quarter of 2015.

In South Africa, during 2014, the exploration well drilled on Block 11B/12B was suspended due to mechanical issues with marine equipment on the drilling rig. The rig safely left the well location and, as the available drilling window had ended, it was demobilized by the operator. The South African authorities have formally confirmed that the well drilled satisfies the work obligation for the initial period of the Block 11B/12B Exploration Right. The operator is reviewing the course of action to re-enter the well, and has indicated drilling operations are unlikely to resume in the area before 2016.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**2014**		2013		2012
Working capital deficit (1)	**$**	**673**	$	1,574	$	1,264
Long-term debt (2) (3)	**$**	**14,002**	$	9,661	$	8,736
Shareholders' equity						
Share capital	**$**	**4,432**	$	3,854	$	3,709
Retained earnings		**24,408**		21,876		20,516
Accumulated other comprehensive income		**51**		42		58
Total	**$**	**28,891**	$	25,772	$	24,283
Debt to book capitalization (3) (4)		**33%**		27%		26%
Debt to market capitalization (3) (5)		**26%**		20%		22%
After-tax return on average common shareholders' equity (6)		**14%**		9%		8%
After-tax return on average capital employed (3) (7)		**10%**		7%		7%

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.
(2) Includes the current portion of long-term debt (2014 – $980 million; 2013 – $1,444 million; 2012 – $798 million).
(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and transaction costs.
(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.
(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.
(6) Calculated as net earnings for the twelve month trailing period; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed for the year.

At December 31, 2014, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. In addition, the Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs supported by its multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring cash flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to declining commodity prices in late 2014, the Company exercised its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. During the first quarter of 2015, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. In addition, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018; and,
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

During 2013, the Company established a US commercial paper program. Borrowings of up to a maximum US$1,500 million are authorized. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

At December 31, 2014, the Company had in place bank credit facilities of $5,627 million, of which approximately $2,643 million, net of commercial paper issuances of $580 million, was available for general corporate purposes. Subsequent to December 31, 2014, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018 and extended the existing $1,000 million non-revolving term credit facility originally maturing March 2016 to January 2017.

During 2014, the Company repaid US$500 million of 1.45% notes and US$350 million of 4.90% notes. The Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million. In addition, the Company issued US$500 million of 3.80% notes due April 2024, US$600 million of 1.75% notes due January 2018, and US$600 million of 3.90% notes due February 2025. Proceeds from the securities were used to repay bank indebtedness.

During 2014, the Company issued $500 million of 2.60% medium-term notes due December 2019 and $500 million of 3.55% medium-term notes due June 2024. Proceeds from the securities were used for general corporate purposes and repayment of bank indebtedness.

At December 31, 2014, the Company had $400 million of long-term debt maturing over the next 12 months ($400 million due June 2015).

Long-term debt was $14,002 million at December 31, 2014, resulting in a debt to book capitalization ratio of 33% (December 31, 2013 – 27%; December 31, 2012 – 26%). This ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. The Company has hedged a portion of its production for 2015 at prices that protect investment returns to support ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at December 31, 2014 are discussed in note 9 to the Company's consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at March 4, 2015, 50,000 bbl/d of currently forecasted 2015 crude oil volumes were hedged using price collars. The Company has also entered into 30,000 bbl/d of crude oil WCS differential swaps in the first quarter of 2015. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2014 are discussed in note 17 to the Company's consolidated financial statements.

SHARE CAPITAL

As at December 31, 2014, there were 1,091,837,000 common shares outstanding (December 31, 2013 – 1,087,322,000 common shares) and 71,708,000 stock options outstanding. As at March 3, 2015, the Company had 1,092,528,000 common shares outstanding and 70,576,000 stock options outstanding.

On March 4, 2015, the Board of Directors approved an increase in the annual dividend to $0.92 per common share (previous annual dividend rate of $0.90 per common share), beginning with the quarterly dividend payable on April 1, 2015 at $0.23 per common share. This reflects confidence in the Company's cash flow and provides a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

During 2014, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the TSX and the NYSE, during the twelve month period commencing April 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014.

During 2014, the Company purchased for cancellation 10,095,000 common shares at a weighted average price of $44.85 per common share for a total cost of $453 million. Retained earnings were reduced by $414 million, representing the excess of the purchase price of common shares over their average carrying value.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2014:

($ millions)	2015	2016	2017	2018	2019	Thereafter
Product transportation and pipeline	$ 442	$ 334	$ 301	$ 268	$ 237	$ 1,512
Offshore equipment operating leases and offshore drilling	$ 341	$ 92	$ 66	$ 59	$ 19	$ –
Long-term debt (1)	$ 980	$ 2,397	$ 2,153	$ 1,160	$ 1,000	$ 6,395
Interest and other financing expense (2)	$ 555	$ 525	$ 445	$ 378	$ 350	$ 4,202
Office leases	$ 42	$ 42	$ 44	$ 46	$ 47	$ 284
Other	$ 204	$ 125	$ 40	$ 1	$ –	$ –

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts or transaction costs.
(2) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2014.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

RESERVES

For the years ended December 31, 2014, 2013 and 2012, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's proved and proved plus probable crude oil, NGLs and natural gas reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities - Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

The following tables summarize the company gross proved and proved plus probable reserves using forecast prices and costs as at December 31, 2014, prepared in accordance with NI 51-101 reserves disclosures:

Proved Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	440	244	258	1,157	2,211	4,305	110	5,137
Discoveries	1	–	–	–	–	14	1	5
Extensions	7	29	–	91	–	121	5	152
Infill Drilling	4	12	–	–	–	562	32	142
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	31	–	–	–	–	1,407	34	300
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(17)	(1)	–	–	(4)	(58)	(1)	(33)
Technical Revisions	9	(3)	34	8	(9)	219	20	97
Production	(29)	(52)	(18)	(39)	(40)	(568)	(13)	(288)
December 31, 2014	**445**	**229**	**274**	**1,217**	**2,158**	**6,001**	**188**	**5,511**

Proved Plus Probable Reserves	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2013	644	334	362	2,170	3,289	6,109	174	7,991
Discoveries	2	–	–	–	–	17	1	6
Extensions	12	41	–	134	358	178	8	583
Infill Drilling	7	16	1	–	–	741	43	191
Improved Recovery	–	–	–	–	–	–	–	–
Acquisitions	40	–	–	–	–	1,892	47	403
Dispositions	(1)	–	–	–	–	(1)	–	(1)
Economic Factors	(3)	(1)	–	–	(11)	(49)	(1)	(24)
Technical Revisions	(12)	(21)	50	47	(3)	(181)	(1)	30
Production	(29)	(52)	(18)	(39)	(40)	(568)	(13)	(288)
December 31, 2014	**660**	**317**	**395**	**2,312**	**3,593**	**8,138**	**258**	**8,891**

At December 31, 2014, the company gross proved crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 4,511 MMbbl, and gross proved plus probable crude oil, bitumen (thermal oil), SCO and NGLs reserves totaled 7,535 MMbbl. Proved reserve additions and revisions replaced 148% of 2014 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 246 MMbbl, and additions to proved plus probable reserves amounted to 709 MMbbl. Net positive revisions amounted to 36 MMbbl for proved reserves and 44 MMbbl for proved plus probable reserves, primarily due to technical revisions to prior estimates.

At December 31, 2014, the company gross proved natural gas reserves totaled 6,001 Bcf, and gross proved plus probable natural gas reserves totaled 8,138 Bcf. Proved reserve additions and revisions replaced 399% of 2014 production. Additions to proved reserves resulting from exploration and development activities, acquisitions and future offset additions amounted to 2,103 Bcf, and additions to proved plus probable reserves amounted to 2,827 Bcf. Net positive revisions amounted to 161 Bcf for proved reserves and net negative revisions amounted to 230 Bcf for proved plus probable reserves, primarily due to technical revisions to prior estimates.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves.

Additional reserves disclosure is annually disclosed in the AIF and the "Supplementary Oil and Gas Information" section of the Company's Annual Report.

RISKS AND UNCERTAINTIES

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- The ability to find, produce and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserve revisions due to economic and technical factors. Reserve revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserve estimates;
- Volatility in the prevailing prices of crude oil and NGLs and natural gas;
- Regulatory risk related to approval for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired properties and/or companies;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to fluctuating exchange rates on the Company's US dollar denominated debt and as all sales are predominantly based on US dollar denominated benchmarks;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- Future legislative and regulatory developments related to environmental regulation;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations;
- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- The access to markets for the Company's products; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to help mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity price, foreign currency and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with substantially all investment grade financial institutions and other entities. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2014.

ENVIRONMENT

The Company continues to invest in people, technologies, facilities and infrastructure to recover and process crude oil and natural gas resources efficiently and in an environmentally sustainable manner.

The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation, particularly in North America and the North Sea. Existing and expected legislation and regulations require the Company to address and mitigate the effect of its activities on the environment. Increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings and cash flow from operations.

The Company's associated environmental risk management strategies focus on working with legislators and regulators to ensure that any new or revised policies, legislation or regulations properly reflect a balanced approach to sustainable development. Specific measures in response to existing or new legislation include a focus on the Company's energy efficiency, air emissions management, released water quality, reduced fresh water use and the minimization of the impact on the landscape. Training and due diligence for operators and contractors are key to the effectiveness of the Company's environmental management programs and the prevention of incidents. The Company's environmental risk management strategies employ an Environmental Management Plan (the "Plan"). Details of the Plan, along with performance results, are presented to, and reviewed by, the Board of Directors quarterly.

The Company's Plan and operating guidelines focus on minimizing the impact of operations while meeting regulatory requirements, regional management frameworks, industry operating standards and guidelines, and internal corporate standards. The Company, as part of this Plan, has implemented a proactive program that includes:

- An internal environmental compliance audit and inspection program of the Company's operating facilities;
- A suspended well inspection program to support future development or eventual abandonment;
- Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
- An effective surface reclamation program;
- A due diligence program related to groundwater monitoring;
- An active program related to preventing and reclaiming spill sites;
- A solution gas conservation program;
- A program to replace the majority of fresh water for steaming with brackish water;
- Water programs to improve efficiency of use, recycle rates and water storage;
- Environmental planning for all projects to assess impacts and to implement avoidance and mitigation programs;
- Reporting for environmental liabilities;
- A program to optimize efficiencies at the Company's operated facilities;
- Continued evaluation of new technologies to reduce environmental impacts and support for Canada's Oil Sands Innovation Alliance ("COSIA");
- CO_2 reduction programs including the injection of CO_2 into tailings and for use in EOR;
- A program in place related to progressive reclamation and tailings management at Horizon; and
- Participation and support for the Joint Oil Sands Monitoring Program.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.6% (2013 – 5.0%; 2012 – 4.3%). For 2014, the Company's capital expenditures included $346 million for abandonment expenditures (2013 – $207 million; 2012 – $204 million). The Company's estimated discounted ARO at December 31, 2014 was as follows:

($ millions)		**2014**		2013
Exploration and Production				
North America	**$**	**2,012**	$	1,707
North Sea		**1,169**		1,090
Offshore Africa		**255**		225
Oil Sands Mining and Upgrading		**783**		1,138
Midstream		**2**		2
	$	**4,221**	$	4,162

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine site, upgrading facilities and tailings, and offshore production platforms. Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on engineering estimates of current costs in accordance with present legislation, industry operating practice and the expected timing of abandonment. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers, is working with Canadian legislators and regulators as they develop and implement new GHG emission laws and regulations. Internally, the Company is pursuing an integrated emissions reduction strategy, to ensure that it is able to comply with existing and future emissions reduction requirements, for both GHGs and air pollutants (such as sulphur dioxide and oxides of nitrogen). The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness.

In Canada, the federal government has indicated its intent to develop regulations to address industrial GHG emissions, as part of the national GHG reduction target. The federal government is also developing a comprehensive management system for air pollutants, and has released draft regulations pertaining to certain boilers, heaters and compressor engines operated by the Company.

In the Province of Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Four of the Company's facilities, the Horizon facility, the Primrose/Wolf Lake in situ heavy crude oil facilities, the Hays sour natural gas plant, and the Wapiti gas plant are subject to compliance under the regulations. The Kirby South in situ heavy crude oil facility will be subject to compliance under the regulations in 2016. In the Province of British Columbia, carbon tax is currently being assessed at $30/tonne of CO_2e on fuel consumed and gas flared in the province. The province of Saskatchewan released draft GHG regulations that regulate facilities emitting more than 50 kilotonnes of CO_2e annually and will likely require the North Tangleflags in situ heavy oil facility to meet the reduction target for its GHG emissions once the governing legislation comes into force. In the UK, GHG regulations have been in effect since 2005. In Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. In Phase 2 (2008 – 2012) the Company's CO_2 allocation was decreased below the Company's operations emissions. In Phase 3 (2013 – 2020) the Company's CO_2 allocation was further reduced. The Company continues to focus on implementing reduction programs based on efficiency audits to reduce CO_2 emissions at its major facilities and on trading mechanisms to ensure compliance with requirements now in effect.

The United States Environmental Protection Agency ("EPA") is proceeding to regulate GHGs under the Clean Air Act. This EPA action has been subject to legal and political challenges, the outcome of which cannot be predicted. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the United States. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

There are a number of unresolved issues in relation to Canadian federal and provincial GHG regulatory requirements. Key among them is the form of regulation, an appropriate common facility emission level, availability and duration of compliance mechanisms, and resolution of federal/provincial harmonization agreements. The Company continues to pursue GHG emission reduction initiatives including: solution gas conservation, compressor optimization to improve fuel gas efficiency, CO_2 capture and sequestration in oil sands tailings, CO_2 capture and storage in association with EOR, and participation in COSIA.

The additional requirements of enacted or proposed GHG regulations on the Company's operations may increase capital expenditures and operating expenses, including those related to Horizon and the Company's other existing and certain planned oil sands projects. This may have an adverse effect on the Company's future net earnings and cash flow from operations.

Air pollutant standards and guidelines are being developed federally and provincially and the Company is participating in these discussions. Ambient air quality and sector based reductions in air emissions are being reviewed. Through Company and industry participation with stakeholders, guidelines are being developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material.

Critical accounting policies and estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting policies and estimates in preparing its consolidated financial statements.

A) DEPLETION, DEPRECIATION AND AMORTIZATION AND IMPAIRMENT

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in "Crude Oil and Natural Gas Reserves".

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGU's.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the specific assets at the CGU level.

B) CRUDE OIL AND NATURAL GAS RESERVES

Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations, and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserve estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

C) ASSET RETIREMENT OBLIGATIONS

The Company is required to recognize a liability for ARO associated with its property, plant and equipment. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total ARO amount. These individual assumptions can be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 4.6%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense in net earnings. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

D) INCOME TAXES

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted as at the date of the balance sheet. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will likely be due.

E) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

F) PURCHASE PRICE ALLOCATIONS

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of the acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in "Crude Oil and Natural Gas Reserves". Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future operating and development costs, to arrive at estimated future net revenues for the properties acquired.

G) SHARE-BASED COMPENSATION

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise behavior and future forfeiture rates. At each period end, stock options outstanding are remeasured for subsequent changes in the fair value of the liability.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued in November, 2013. IFRS 9 replaced the sections of IAS 39 "Financial Instruments: Recognition and Measurement" that relate to the classification and measurement of financial instruments and hedge accounting.

IFRS 9 replaced the multiple classification and measurement models for financial assets with a new model that has only two measurement categories: amortized cost and fair value through profit or loss. This determination is made at initial recognition. For financial liabilities, the new standard retained most of the IAS 39 requirements. The main change arose in cases where the Company chose to designate a financial liability as fair value through profit or loss. In these situations, the portion of the fair value change related to the Company's own credit risk is recognized in other comprehensive income rather than net earnings. As a result of adopting IFRS 9, all of the Company's financial assets as at December 31, 2013 were reclassified from loans and receivables at amortized cost to financial assets at amortized cost. There were no changes to the classifications of the Company's financial liabilities. In addition, there were no changes in the carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. The classification and measurement guidance was adopted retrospectively in accordance with the transition provisions of IFRS 9.

The Company also adopted the new hedge accounting guidance in IFRS 9. The new hedge accounting guidance replaced strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company's risk management objectives for financial and non-financial risk exposures. IFRS 9 also allows the Company to hedge risk components of non-financial items which meet certain measurability or identifiable characteristics.

Upon adoption of IFRS 9, all of the Company's existing hedging relationships that qualified for hedge accounting under IAS 39 were reassessed with respect to the new hedge accounting requirements in IFRS 9. The hedging relationships were continued under IFRS 9. The hedge accounting requirements in IFRS 9 were applied prospectively in accordance with the transition provisions of IFRS 9.

After adoption of IFRS 9, the Company's accounting policies are substantially the same as at December 31, 2013, except for the change in financial asset categories as discussed above.

Effective January 1, 2014, the Company adopted an amendment to IAS 32 "Financial instruments: Presentation" relating to offsetting financial assets and financial liabilities. This amendment clarifies that the right of set-off must not be contingent on a future event. The amendment did not have a significant impact on the Company's consolidated financial statements.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. The new standard is required to be adopted retrospectively effective January 1, 2017, with earlier adoption permitted. The Company is currently assessing the impact of IFRS 15 on its consolidated financial statements.

In May 2014 the IASB issued an amendment to IFRS 11 "Joint Arrangements" to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. This amendment is effective January 1, 2016 and is to be applied prospectively. Adoption of this amended standard is not expected to result in a significant impact in the presentation of the Company's consolidated financial statements.

In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018. The Company is currently assessing the impact of this amendment on its consolidated financial statements.

CONTROL ENVIRONMENT

The Company's management, including the President and the Chief Financial Officer and Senior Vice-President, Finance, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2014, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management also performed an assessment of internal control over financial reporting as at December 31, 2014, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2014 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems 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.

OUTLOOK

The Company continues to implement its strategy of maintaining a large portfolio of varied projects, which the Company believes will enable it, over an extended period of time, to provide consistent growth in production and create shareholder value. Annual budgets are developed, scrutinized throughout the year and revised if necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

Included in the Company's original 2015 budget was approximately $2,000 million of capital flexibility, which allows the Company to reallocate capital over 2015 as required. In response to declining commodity prices, in December 2014 the Company proactively reviewed its capital allocation strategy and in January 2015 announced that it would access this capital flexibility to reduce capital spending by approximately $2,400 million. Subsequently, capital expenditure guidance for 2015 has been further reduced by $150 million as a result of the reduction in scope of the originally planned 2015 Horizon maintenance turnaround from 35 days to 6 days. The Company has significant additional capital flexibility in 2015 to further curtail capital spending if required or increase capital spending if commodity prices strengthen.

As a result of the reduced capital expenditure targets for 2015, the Company revised its 2015 targeted annual production levels before royalties to average between 562,000 bbl/d and 602,000 bbl/d of crude oil and NGLs and between 1,730 MMcf/d and 1,770 MMcf/d of natural gas.

Capital expenditures in 2015 are currently targeted to be as follows:

($ millions)		2015
Exploration and Production		
North America natural gas and NGLs	$	490
North America crude oil		980
International crude oil		1,165
Thermal In Situ Oil Sands		
Primrose and future		300
Kirby South		55
Kirby North Phase 1		105
Net acquisitions, Midstream and other		70
Total Exploration and Production	$	3,165
Oil Sands Mining and Upgrading		
Project Capital		
Directive 74		55
Phase 2A		45
Phase 2B		1,210
Phase 3		550
Owner's Costs and Other		340
Total Project Capital	$	2,200
Technology and Phase 4		20
Sustaining capital		300
Turnarounds and reclamation		10
Capitalized interest and other		345
Total Oil Sands Mining and Upgrading	$	2,875
Total	$	6,040

SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flow from operations and net earnings from changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2014, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flow from operations ($ millions)	Cash flow from operations (per common share, basic)	Net earnings ($ millions)	Net earnings (per common share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl [(1)]				
Excluding financial derivatives	$ 156	$ 0.14	$ 156	$ 0.14
Including financial derivatives	$ 142	$ 0.13	$ 142	$ 0.13
Natural gas – AECO C$0.10/Mcf [(1)]	$ 38	$ 0.03	$ 38	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 121	$ 0.11	$ 78	$ 0.07
Natural gas – 10 MMcf/d	$ 7	$ 0.01	$ 1	$ –
Foreign currency rate change				
$0.01 change in US$ [(1)]				
Including financial derivatives	$ 112 – 115	$ 0.10	$ 51 – 52	$ 0.05
Interest rate change – 1%	$ 22	$ 0.02	$ 22	$ 0.02

(1) For details of financial instruments in place, refer to note 17 to the Company's consolidated financial statements as at December 31, 2014.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2014	2013	2012
Crude oil and NGLs (bbl/d)							
North America – Exploration and Production	**348,187**	**400,154**	**404,114**	**409,976**	**390,814**	343,699	326,829
North America – Oil Sands Mining and Upgrading	**113,095**	**119,236**	**82,012**	**128,090**	**110,571**	100,284	86,077
North Sea	**16,715**	**12,615**	**18,197**	**21,927**	**17,380**	18,334	19,824
Offshore Africa	**10,791**	**13,164**	**13,684**	**12,047**	**12,429**	15,923	18,648
Total	**488,788**	**545,169**	**518,007**	**572,040**	**531,194**	478,240	451,378
Natural gas (MMcf/d)							
North America	**1,147**	**1,606**	**1,644**	**1,705**	**1,527**	1,130	1,198
North Sea	**7**	**5**	**7**	**10**	**7**	4	2
Offshore Africa	**21**	**23**	**23**	**18**	**21**	24	20
Total	**1,175**	**1,634**	**1,674**	**1,733**	**1,555**	1,158	1,220
Barrels of oil equivalent (BOE/d)							
North America – Exploration and Production	**539,246**	**667,737**	**678,062**	**694,138**	**645,227**	531,961	526,460
North America – Oil Sands Mining and Upgrading	**113,095**	**119,236**	**82,012**	**128,090**	**110,571**	100,284	86,077
North Sea	**17,960**	**13,502**	**19,320**	**23,664**	**18,629**	19,029	20,151
Offshore Africa	**14,346**	**16,996**	**17,537**	**15,028**	**15,983**	19,888	21,977
Total	**684,647**	**817,471**	**796,931**	**860,920**	**790,410**	671,162	654,665

PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2014	2013	2012
Crude oil and NGLs ($/bbl) (1)							
Sales price (2)	**$ 79.68**	**$ 87.03**	**$ 79.99**	**$ 62.80**	**$ 77.04**	$ 73.81	$ 72.44
Transportation	**2.49**	**2.74**	**2.32**	**2.15**	**2.41**	2.22	2.20
Realized sales price, net of transportation	**77.19**	**84.29**	**77.67**	**60.65**	**74.63**	71.59	70.24
Royalties	**14.05**	**15.62**	**13.66**	**9.05**	**12.99**	11.13	10.67
Production expense	**19.18**	**19.33**	**15.99**	**18.69**	**18.25**	17.14	16.11
Netback	**$ 43.96**	**$ 49.34**	**$ 48.02**	**$ 32.91**	**$ 43.39**	$ 43.32	$ 43.46
Natural gas ($/Mcf) (1)							
Sales price (2)	**$ 5.69**	**$ 5.06**	**$ 4.54**	**$ 4.32**	**$ 4.83**	$ 3.58	$ 2.70
Transportation	**0.30**	**0.26**	**0.26**	**0.28**	**0.27**	0.28	0.26
Realized sales price, net of transportation	**5.39**	**4.80**	**4.28**	**4.04**	**4.56**	3.30	2.44
Royalties	**0.62**	**0.41**	**0.32**	**0.24**	**0.38**	0.18	0.09
Production expense	**1.61**	**1.52**	**1.45**	**1.39**	**1.48**	1.42	1.31
Netback	**$ 3.16**	**$ 2.87**	**$ 2.51**	**$ 2.41**	**$ 2.70**	$ 1.70	$ 1.04
Barrels of oil equivalent ($/BOE) (1)							
Sales price (2)	**$ 63.14**	**$ 64.69**	**$ 59.56**	**$ 48.23**	**$ 58.48**	$ 56.46	$ 52.85
Transportation	**2.29**	**2.35**	**2.08**	**2.05**	**2.18**	2.10	2.04
Realized sales price, net of transportation	**60.85**	**62.34**	**57.48**	**46.18**	**56.30**	54.36	50.81
Royalties	**10.42**	**10.49**	**9.12**	**6.10**	**8.90**	7.74	7.07
Production expense	**15.82**	**15.35**	**13.15**	**14.66**	**14.67**	14.24	13.14
Netback	**$ 34.61**	**$ 36.50**	**$ 35.21**	**$ 25.42**	**$ 32.73**	$ 32.38	$ 30.60

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of blending costs and excluding risk management activities.

PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2014	2013	2012
Crude oil and NGLs ($/bbl) (1)							
SCO sales price	**$ 107.82**	**$ 112.69**	**$ 103.91**	**$ 79.23**	**$ 100.27**	$ 100.75	$ 90.74
Bitumen royalties (2)	**5.06**	**6.77**	**7.17**	**4.44**	**5.77**	5.11	4.34
Transportation	**1.96**	**1.53**	**2.28**	**1.76**	**1.85**	1.57	1.83
Adjusted cash production costs	**41.11**	**36.61**	**37.13**	**34.34**	**37.18**	40.57	42.83
Netback	**$ 59.69**	**$ 67.78**	**$ 57.33**	**$ 38.69**	**$ 55.47**	$ 53.50	$ 41.74

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.
(2) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2014	2013
TSX – C$						
Trading volume (thousands)	**174,223**	**127,633**	**149,886**	**265,838**	**717,580**	683,003
Share Price ($/share)						
High	**$ 42.49**	**$ 49.22**	**$ 49.57**	**$ 43.75**	**$ 49.57**	$ 36.04
Low	**$ 34.72**	**$ 42.20**	**$ 42.89**	**$ 31.00**	**$ 31.00**	$ 28.44
Close	**$ 42.37**	**$ 49.03**	**$ 43.51**	**$ 35.92**	**$ 35.92**	$ 35.94
Market capitalization as at December 31 ($ millions)					**$ 39,219**	$ 39,078
Shares outstanding (thousands)					**1,091,837**	1,087,322
NYSE – US$						
Trading volume (thousands)	**175,885**	**143,772**	**149,812**	**343,052**	**812,521**	645,403
Share Price ($/share)						
High	**$ 38.44**	**$ 46.14**	**$ 46.65**	**$ 39.12**	**$ 46.65**	$ 33.92
Low	**$ 31.56**	**$ 38.23**	**$ 38.38**	**$ 26.53**	**$ 26.53**	$ 26.98
Close	**$ 38.37**	**$ 45.91**	**$ 38.84**	**$ 30.88**	**$ 30.88**	$ 33.84
Market capitalization as at December 31 ($ millions)					**$ 33,716**	$ 36,795
Shares outstanding (thousands)					**1,091,837**	1,087,322

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2014; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2014.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

Steve W. Laut
President

Corey B. Bieber, CA
Chief Financial Officer and
Senior Vice-President, Finance

Murray G. Harris, CA
Vice-President, Financial Controller
and Horizon Accounting

Calgary, Alberta, Canada
March 4, 2015

MANAGEMENT'S ASSESSMENT OF INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a–15(f) and 15d–15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer and Senior Vice-President, Finance, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting is effective as at December 31, 2014. Management recognizes that all internal control systems have 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.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2014, as stated in their Auditor's Report.

Steve W. Laut
President

Corey B. Bieber, CA
Chief Financial Officer and
Senior Vice-President, Finance

Calgary, Alberta, Canada
March 4, 2015

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF CANADIAN NATURAL RESOURCES LIMITED

We have completed integrated audits of Canadian Natural Resources Limited's 2014, 2013, and 2012 consolidated financial statements and its internal control over financial reporting as at December 31, 2014. Our opinions, based on our audits are presented below.

REPORT ON THE CONSOLIDATED FINANCIAL STATEMENTS

We have audited the accompanying consolidated financial statements of Canadian Natural Resources Limited, which comprise the consolidated balance sheets as at December 31, 2014 and December 31, 2013 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2014, and the related notes.

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 the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement. Canadian generally accepted auditing standards also 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 Canadian Natural Resources Limited as at December 31, 2014 and December 31, 2013 and its financial performance and its cash flows for each of the three years in the period ended December 31, 2014 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

MANAGEMENT'S RESPONSIBILITY FOR INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on the company'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 Canadian Natural Resources Limited'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, Canadian Natural Resources Limited maintained, in all material respects, effective internal control over financial reporting as at December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada
March 4, 2015

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)	Note	2014	2013
ASSETS			
Current assets			
Cash and cash equivalents		**$ 25**	$ 16
Accounts receivable		**1,889**	1,427
Current income taxes		**228**	–
Inventory	5	**665**	632
Prepaids and other		**172**	141
Current portion of other long-term assets	8	**510**	–
		3,489	2,216
Exploration and evaluation assets	6	**3,557**	2,609
Property, plant and equipment	7	**52,480**	46,487
Other long-term assets	8	**674**	442
		$ 60,200	$ 51,754
LIABILITIES			
Current liabilities			
Accounts payable		**$ 564**	$ 637
Accrued liabilities		**3,279**	2,519
Current income taxes		**–**	359
Current portion of long-term debt	9	**980**	1,444
Current portion of other long-term liabilities	10	**319**	275
		5,142	5,234
Long-term debt	9	**13,022**	8,217
Other long-term liabilities	10	**4,175**	4,348
Deferred income taxes	11	**8,970**	8,183
		31,309	25,982
SHAREHOLDERS' EQUITY			
Share capital	12	**4,432**	3,854
Retained earnings		**24,408**	21,876
Accumulated other comprehensive income	13	**51**	42
		28,891	25,772
		$ 60,200	$ 51,754

Commitments and contingencies (note 18).

Approved by the Board of Directors on March 4, 2015

Catherine M. Best
Chair of the Audit Committee and Director

N. Murray Edwards
Chairman of the Board of Directors and Director

CONSOLIDATED STATEMENTS OF EARNINGS

For the years ended December 31 (millions of Canadian dollars, except per common share amounts)	Note	**2014**	2013	2012
Product sales		**$ 21,301**	$ 17,945	$ 16,195
Less: royalties		**(2,438)**	(1,800)	(1,606)
Revenue		**18,863**	16,145	14,589
Expenses				
Production		**5,265**	4,559	4,249
Transportation and blending		**3,232**	2,938	2,752
Depletion, depreciation and amortization	7	**4,880**	4,844	4,328
Administration		**367**	335	270
Share-based compensation	10	**66**	135	(214)
Asset retirement obligation accretion	10	**193**	171	151
Interest and other financing expense	16	**323**	279	364
Risk management activities	17	**(800)**	(77)	120
Foreign exchange loss (gain)		**303**	210	(49)
Gain on corporate acquisitions/disposition of properties	6, 7	**(137)**	(289)	–
Equity loss from investment	8	**8**	4	9
		13,700	13,109	11,980
Earnings before taxes		**5,163**	3,036	2,609
Current income tax expense	11	**427**	735	747
Deferred income tax expense (recovery)	11	**807**	31	(30)
Net earnings		**$ 3,929**	$ 2,270	$ 1,892
Net earnings per common share				
Basic	15	**$ 3.60**	$ 2.08	$ 1.72
Diluted	15	**$ 3.58**	$ 2.08	$ 1.72

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (millions of Canadian dollars)	**2014**	2013	2012
Net earnings	**$ 3,929**	$ 2,270	$ 1,892
Items that may be reclassified subsequently to net earnings			
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized income (loss), net of taxes of $nil (2013 – $nil, 2012 – $4 million)	**5**	(4)	31
Reclassification to net earnings, net of taxes of $1 million (2013 – $nil, 2012 – $nil)	**8**	(1)	(7)
	13	(5)	24
Foreign currency translation adjustment			
Translation of net investment	**(4)**	(11)	8
Other comprehensive income (loss), net of taxes	**9**	(16)	32
Comprehensive income	**$ 3,938**	$ 2,254	$ 1,924

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

For the years ended December 31 (millions of Canadian dollars)	Note	2014	2013	2012
Share capital	12			
Balance – beginning of year		**$ 3,854**	$ 3,709	$ 3,507
Issued upon exercise of stock options		**488**	130	194
Previously recognized liability on stock options exercised for common shares		**129**	50	45
Purchase of common shares under Normal Course Issuer Bid		**(39)**	(35)	(37)
Balance – end of year		**4,432**	3,854	3,709
Retained earnings				
Balance – beginning of year		**21,876**	20,516	19,365
Net earnings		**3,929**	2,270	1,892
Purchase of common shares under Normal Course Issuer Bid	12	**(414)**	(285)	(281)
Dividends on common shares	12	**(983)**	(625)	(460)
Balance – end of year		**24,408**	21,876	20,516
Accumulated other comprehensive income	13			
Balance – beginning of year		**42**	58	26
Other comprehensive income (loss), net of taxes		**9**	(16)	32
Balance – end of year		**51**	42	58
Shareholders' equity		**$ 28,891**	$ 25,772	$ 24,283

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (millions of Canadian dollars)	Note	2014	2013	2012
Operating activities				
Net earnings		**$ 3,929**	$ 2,270	$ 1,892
Non-cash items				
Depletion, depreciation and amortization		**4,880**	4,844	4,328
Share-based compensation		**66**	135	(214)
Asset retirement obligation accretion		**193**	171	151
Unrealized risk management (gain) loss		**(451)**	39	(42)
Unrealized foreign exchange loss		**256**	226	129
Realized foreign exchange loss (gain) on repayment of US dollar debt securities		**36**	(12)	(210)
Equity loss from investment		**8**	4	9
Deferred income tax expense (recovery)		**807**	31	(30)
Gain on corporate acquisitions/disposition of properties		**(137)**	(289)	–
Current income tax on disposition of properties		**–**	58	–
Other		**(38)**	(19)	(47)
Abandonment expenditures		**(346)**	(207)	(204)
Net change in non-cash working capital	19	**(744)**	(33)	447
		8,459	7,218	6,209
Financing activities				
Issue of bank credit facilities and commercial paper, net		**1,195**	803	172
Issue of medium-term notes, net		**992**	98	498
Issue (repayment) of US dollar debt securities, net	9	**1,482**	(398)	(344)
Issue of common shares on exercise of stock options		**488**	130	194
Purchase of common shares under Normal Course Issuer Bid		**(453)**	(320)	(318)
Dividends on common shares		**(955)**	(523)	(444)
Net change in non-cash working capital	19	**(22)**	(23)	(37)
		2,727	(233)	(279)
Investing activities				
Net (expenditures) proceeds on exploration and evaluation assets	19	**(1,190)**	144	(309)
Net expenditures on property, plant and equipment	19	**(10,208)**	(7,211)	(5,795)
Current income tax on disposition of properties		**–**	(58)	–
Investment in other long-term assets		**(113)**	–	2
Net change in non-cash working capital	19	**334**	119	175
		(11,177)	(7,006)	(5,927)
Increase (decrease) in cash and cash equivalents		**9**	(21)	3
Cash and cash equivalents – beginning of year		**16**	37	34
Cash and cash equivalents – end of year		**$ 25**	$ 16	$ 37
Interest paid		**$ 521**	$ 460	$ 464
Income taxes paid		**$ 792**	$ 357	$ 639

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855-2 Street S.W., Calgary, Alberta, Canada.

The Company's consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The accounting policies adopted by the Company under IFRS are set out below. The Company has consistently applied the same accounting policies throughout all periods presented, except where IFRS permits new accounting standards to be adopted prospectively (see note 2).

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries are all entities over which the Company has control. Subsidiaries are consolidated from the date on which the Company obtains control. They are deconsolidated from the date that control ceases.

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditure overruns, liquidity concerns, financial restructuring of the investee or significant adverse changes in the technological, economic or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(B) SEGMENTED INFORMATION

Operating segments have been determined based on the nature of the Company's activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company's chief operating decision makers.

(C) CASH AND CASH EQUIVALENTS

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with an original term to maturity at purchase of three months or less are reported as cash equivalents in the consolidated balance sheets.

(D) INVENTORY

Inventory is primarily comprised of product inventory and materials and supplies. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels. Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, directly attributable overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices, and for materials and supplies is based on current market prices as at the date of the consolidated balance sheets.

(E) EXPLORATION AND EVALUATION ASSETS

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of Cash Generating Units ("CGUs"), aggregated at the segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

(F) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Assets under construction are not depleted or depreciated until available for their intended use. The capitalized value of a finance lease is included in property, plant and equipment.

Exploration and Production

The cost of an asset comprises its acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

Oil Sands Mining and Upgrading

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs.

Mine-related costs are depleted using the unit-of-production method based on Horizon proved reserves. Costs of the upgrader and related infrastructure located on the Horizon site are depreciated on the unit-of-production method based on productive capacity of the upgrader and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 15 years.

Midstream and Head Office

The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream and head office assets. Midstream assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are depreciated on a declining balance basis.

Useful lives

The depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

Derecognition

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is recognized in net earnings within depletion, depreciation and amortization.

Major maintenance expenditures

Inspection costs associated with major maintenance turnarounds are capitalized and depreciated over the period to the next major maintenance turnaround. All other maintenance costs are expensed as incurred.

Impairment

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGUs, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, had no impairment loss been recognized for the asset in prior periods. A reversal of impairment is recognized in net earnings. After a reversal, the depletion charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

(G) BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in net earnings.

(H) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during the initial development of a mine at Horizon are capitalized to property, plant and equipment. Overburden removal costs incurred during the production of a mine are included in the cost of inventory, unless the overburden removal activity has resulted in a probable inflow of future economic benefits to the Company, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are depleted over the life of the mining reserves that directly benefit from the overburden removal activity.

(I) CAPITALIZED BORROWING COSTS

Borrowing costs attributable to the acquisition, construction or production of qualifying assets are capitalized to the cost of those assets until such time as the assets are substantially available for their intended use. Qualifying assets are comprised of those significant assets that require a period greater than one year to be available for their intended use. All other borrowing costs are recognized in net earnings.

(J) LEASES

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term. Operating lease payments are recognized in net earnings over the lease term.

(K) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on all of its property, plant and equipment based on current legislation and industry operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the obligation as at the date of the balance sheet. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes due to discount rates or estimated future cash flows are capitalized to or derecognized from property, plant, and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

(L) FOREIGN CURRENCY TRANSLATION

Functional and presentation currency

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency"). The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency.

The assets and liabilities of subsidiaries that have a functional currency different from that of the Company are translated into Canadian dollars at the closing rate at the date of the balance sheet, and revenue and expenses are translated at the average rate for the period. Cumulative foreign currency translation adjustments are recognized in other comprehensive income.

When the Company disposes of its 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 other comprehensive income related to the foreign operation are recognized in net earnings.

Transactions and balances

Foreign currency transactions are translated into the functional currency of the Company and its subsidiaries and partnerships using the exchange rates prevailing at the dates of the transactions. Foreign exchange gains and losses resulting from the settlement of foreign currency transactions and from the translation at balance sheet date exchange rates of monetary assets and liabilities denominated in currencies other than the functional currency are recognized in net earnings.

(M) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the sale of crude oil and natural gas is recognized when title passes to the customer, delivery has taken place and collection is reasonably assured. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Revenue represents the Company's share net of royalty payments to governments and other mineral interest owners. Related costs of goods sold are comprised of production, transportation and blending, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

(N) PRODUCTION SHARING CONTRACTS

Production generated from Côte d'Ivoire and Gabon in Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective Government State Oil Companies (the "Governments"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Governments. The Governments' share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the respective PSCs.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date, and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

Income taxes are recognized in net earnings or other comprehensive income, consistent with the items to which they relate.

(P) SHARE-BASED COMPENSATION

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are re-measured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital. The unamortized costs of employer contributions to the Company's share bonus program are included in other long-term assets.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost; financial liabilities at amortized cost; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash, cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are mainly payments of principal and interest. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

Impairment of financial assets

At each reporting date, the Company assesses whether there is objective evidence that a financial asset is impaired. If such evidence exists, an impairment loss is recognized.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost of the financial asset and the present value of the estimated future cash flows, discounted using the instrument's original effective interest rate. Impairment losses on financial assets carried at amortized cost are reversed in subsequent periods if the amount of the loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized.

(R) RISK MANAGEMENT ACTIVITIES

The Company uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The carrying amount of a risk management liability is adjusted for the Company's own credit risk.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect its cash flow for its capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on certain of its long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. Changes in the fair value of interest rate swap contracts designated as fair value hedges and corresponding changes in the fair value of the hedged long-term debt are recognized in interest expense in net earnings. Changes in the fair value of non-designated interest rate swap contracts are recognized in risk management activities in net earnings.

Cross currency swap contracts are periodically used to manage currency exposure on US dollar denominated long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Changes in the fair value of the foreign exchange component of cross currency swap contracts designated as cash flow hedges related to the notional principal amounts are recognized in foreign exchange gains and losses in net earnings. The effective portion of changes in the fair value of the interest rate component of cross currency swap contracts designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to interest expense when the hedged item is recognized in net earnings, with the ineffective portion recognized in risk management activities in net earnings. Changes in the fair value of non-designated cross currency swap contracts are recognized in risk management activities in net earnings.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income and amortized into net earnings in the period in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is derecognized on the consolidated balance sheets and the related long-term debt hedged is no longer revalued for subsequent changes in fair value. The fair value adjustment on the long-term debt at the date of termination of the interest rate swap is amortized to interest expense over the remaining term of the long-term debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not clearly and closely related to the host contract.

(S) COMPREHENSIVE INCOME

Comprehensive income is comprised of the Company's net earnings and other comprehensive income. Other comprehensive income includes the effective portion of changes in the fair value of derivative financial instruments designated as cash flow hedges and foreign currency translation gains and losses arising from the net investment in foreign operations that do not have a Canadian dollar functional currency. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

(U) SHARE CAPITAL

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

(V) DIVIDENDS

Dividends on common shares are recognized in the Company's financial statements in the period in which the dividends are approved by the Board of Directors.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued in November 2013. IFRS 9 replaced the sections of IAS 39 "Financial Instruments: Recognition and Measurement" that relate to the classification and measurement of financial instruments and hedge accounting.

IFRS 9 replaced the multiple classification and measurement models for financial assets with a new model that has only two measurement categories: amortized cost and fair value through profit or loss. This determination is made at initial recognition. For financial liabilities, the new standard retained most of the IAS 39 requirements. The main change arose in cases where the Company chose to designate a financial liability as fair value through profit or loss. In these situations, the portion of the fair value change related to the Company's own credit risk is recognized in other comprehensive income rather than net earnings. As a result of adopting IFRS 9, all of the Company's financial assets as at December 31, 2013 were reclassified from loans and receivables at amortized cost to financial assets at amortized cost. There were no changes to the classifications of the Company's financial liabilities. In addition, there were no changes in the carrying values of the Company's financial instruments as a result of the adoption of IFRS 9. The classification and measurement guidance was adopted retrospectively in accordance with the transition provisions of IFRS 9.

The Company also adopted the new hedge accounting guidance in IFRS 9. The new hedge accounting guidance replaced strict quantitative tests of effectiveness with less restrictive assessments of how well the hedging instrument accomplishes the Company's risk management objectives for financial and non-financial risk exposures. IFRS 9 also allows the Company to hedge risk components of non-financial items which meet certain measurability or identifiable characteristics.

Upon adoption of IFRS 9, all of the Company's existing hedging relationships that qualified for hedge accounting under IAS 39 were reassessed with respect to the new hedge accounting requirements in IFRS 9. The hedging relationships were continued under IFRS 9. The hedge accounting requirements in IFRS 9 were applied prospectively in accordance with the transition provisions of IFRS 9.

After adoption of IFRS 9, the Company's accounting policies are substantially the same as at December 31, 2013, except for the change in financial asset categories as discussed above.

Effective January 1, 2014, the Company adopted an amendment to IAS 32 "Financial instruments: Presentation" relating to offsetting financial assets and financial liabilities. This amendment clarifies that the right of set-off must not be contingent on a future event. The amendment did not have a significant impact on the Company's consolidated financial statements.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. The new standard is required to be adopted retrospectively effective January 1, 2017, with earlier adoption permitted. The Company is currently assessing the impact of IFRS 15 on its consolidated financial statements.

In May 2014, the IASB issued an amendment to IFRS 11 "Joint Arrangements" to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. This amendment is effective January 1, 2016 and is to be applied prospectively. Adoption of this amended standard is not expected to result in a significant impact to the Company's consolidated financial statements.

In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018. The Company is currently assessing the impact of this amendment on its consolidated financial statements.

4. CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

(A) CRUDE OIL AND NATURAL GAS RESERVES

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties, interpretations and judgements. The Company expects that, over time, its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels, and may be affected by changes in commodity prices.

(B) ASSET RETIREMENT OBLIGATIONS

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions of dates of future abandonment and technological advances and estimates of future inflation rates and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, and changes in the date of abandonment due to changes in reserve life. These differences may have a material impact on the estimated provision.

(C) INCOME TAXES

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes liabilities for potential tax audit issues based on assessments of whether additional taxes will likely be due.

(D) FAIR VALUE OF DERIVATIVES AND OTHER FINANCIAL INSTRUMENTS

The fair value of financial instruments that are not traded in an active market is determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates.

(E) PURCHASE PRICE ALLOCATIONS

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation, and amortization expense and impairment tests.

(F) SHARE-BASED COMPENSATION

The Company has made various assumptions in estimating the fair values of the stock options granted under the Option Plan, including expected volatility, expected exercise timing and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the fair value of the liability.

(G) IDENTIFICATION OF CGUS

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

(H) IMPAIRMENT OF ASSETS

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGU's or the asset's fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, discount rates currently ranging from 10% to 12%, and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

(I) CONTINGENCIES

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

5. INVENTORY

		2014		2013
Product inventory	**$**	**332**	$	342
Materials and supplies		**333**		290
	$	**665**	$	632

As a result of a decline in crude oil prices, the Company recorded a write-down of its product inventory of $70 million from cost to net realizable value as at December 31, 2014 (2013 – $nil).

6. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2012	$ 2,564	$ –	$ 47	$ –	$ 2,611
Additions	90	–	29	–	119
Transfers to property, plant and equipment	(84)	–	–	–	(84)
Disposals	–	–	(39)	–	(39)
Foreign exchange adjustments	–	–	2	–	2
At December 31, 2013	2,570	–	39	–	2,609
Additions	**1,103**	**–**	**87**	**–**	**1,190**
Transfers to property, plant and equipment	**(247)**	**–**	**–**	**–**	**(247)**
Foreign exchange adjustments	**–**	**–**	**5**	**–**	**5**
At December 31, 2014	**$ 3,426**	**$ –**	**$ 131**	**$ –**	**$ 3,557**

During 2014, the Company acquired exploration and evaluation assets in connection with the acquisition of certain crude oil and natural gas properties (refer to note 7).

During 2013, the Company disposed of a 50% interest in its exploration right in South Africa, for net cash consideration of US$255 million, including a recovery of US$14 million of past incurred costs, resulting in a pre-tax gain on sale of exploration and evaluation property of $224 million ($166 million after-tax). In the event that a commercial crude oil or natural gas discovery occurs on this exploration right, resulting in the exploration right being converted into a production right, an additional cash payment would be due to the Company at such time, amounting to US$450 million for a commercial crude oil discovery and US$120 million for a commercial natural gas discovery.

7. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2012	$ 50,324	$ 4,574	$ 3,045	$ 16,963	$ 312	$ 270	$ 75,488
Additions	3,630	299	97	2,772	196	38	7,032
Transfers from E&E assets	84	–	–	–	–	–	84
Disposals/derecognitions	(228)	–	–	(369)	–	–	(597)
Foreign exchange adjustments and other	–	327	214	–	–	–	541
At December 31, 2013	53,810	5,200	3,356	19,366	508	308	82,548
Additions	**6,858**	**486**	**193**	**2,728**	**62**	**45**	**10,372**
Transfers from E&E assets	**247**	**–**	**–**	**–**	**–**	**–**	**247**
Disposals/derecognitions	**(309)**	**–**	**–**	**(146)**	**–**	**(1)**	**(456)**
Foreign exchange adjustments and other	**–**	**496**	**309**	**–**	**–**	**–**	**805**
At December 31, 2014	**$ 60,606**	**$ 6,182**	**$ 3,858**	**$ 21,948**	**$ 570**	**$ 352**	**$ 93,516**
Accumulated depletion and depreciation							
At December 31, 2012	$ 24,991	$ 2,709	$ 2,273	$ 1,202	$ 103	$ 182	$ 31,460
Expense	3,551	548	134	582	8	21	4,844
Disposals/derecognitions	(228)	–	–	(369)	–	–	(597)
Foreign exchange adjustments and other	1	210	144	(1)	–	–	354
At December 31, 2013	28,315	3,467	2,551	1,414	111	203	36,061
Expense	**3,880**	**265**	**105**	**596**	**9**	**25**	**4,880**
Disposals/derecognitions	**(309)**	**–**	**–**	**(146)**	**–**	**(1)**	**(456)**
Foreign exchange adjustments and other	**–**	**317**	**234**	**–**	**–**	**–**	**551**
At December 31, 2014	**$ 31,886**	**$ 4,049**	**$ 2,890**	**$ 1,864**	**$ 120**	**$ 227**	**$ 41,036**
Net book value							
- at December 31, 2014	**$ 28,720**	**$ 2,133**	**$ 968**	**$ 20,084**	**$ 450**	**$ 125**	**$ 52,480**
- at December 31, 2013	$ 25,495	$ 1,733	$ 805	$ 17,952	$ 397	$ 105	$ 46,487

Project costs not subject to depletion and depreciation	**2014**	2013
Horizon	**$ 5,492**	$ 4,051
Kirby Thermal Oil Sands – North	**$ 681**	$ 322
Kirby Thermal Oil Sands – South	**$ –**	$ 1,345

On April 1, 2014, the Company completed the acquisition of certain Canadian crude oil and natural gas properties in the North American Exploration and Production segment, including exploration and evaluation assets of $823 million, for cash consideration of $3,110 million, subject to final closing adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with this acquisition, the Company assumed associated asset retirement obligations of $242 million and other long-term liabilities of $49 million. No debt obligations were assumed and no net deferred income tax liabilities were recognized. The above amounts are estimates and may be subject to change based on the receipt of new information.

During 2014, the Company acquired a number of additional producing crude oil and natural gas properties in the North American Exploration and Production segment for net cash consideration of $643 million (2013 – $252 million; 2012 – $144 million). These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company acquired net working capital of $28 million, assumed associated asset retirement obligations of $162 million (2013 – $131 million; 2012 – $12 million) and recognized net deferred income tax assets of $91 million (2013 – $75 million; 2012 – $nil) related to temporary differences in the carrying amount of certain of the acquired properties and their tax bases. No debt obligations were assumed. The Company recognized after-tax gains of $137 million (2013 – $65 million; 2012 – $nil) on these acquisitions. The above amounts are estimates and may be subject to change based on the receipt of new information.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. During 2014, pre-tax interest of $204 million (2013 – $175 million; 2012 – $98 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (2013 – 4.4%; 2012 – 4.8%).

8. OTHER LONG-TERM ASSETS

		2014		2013
Investment in North West Redwater Partnership	**$**	**298**	$	306
North West Redwater Partnership subordinated debt [(1)]		**120**		–
Risk Management (note 17)		**599**		–
Other		**167**		136
		1,184		442
Less: current portion		**510**		–
	$	**674**	$	442

(1) Includes accrued interest.

Other long-term assets include an investment in the 50% owned Redwater Partnership. Based on Redwater Partnership's voting and decision-making structure and legal form, the investment is accounted for using the equity method. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2014, Redwater Partnership, the Company and APMC amended certain terms of the processing agreements. In conjunction with these amendments, in order to provide financing for Project completion based on the current revised Project cost estimate of approximately $8,500 million, the Company, along with APMC, each committed to provide additional funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2014, the Company and APMC each provided $113 million of subordinated debt. Subsequent to December 31, 2014, the Company and APMC each provided an additional $112 million of subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During 2014, Redwater Partnership executed a $3,500 million syndicated credit facility with a group of financial institutions maturing June 2018 and repaid and cancelled its $1,200 million credit facility previously in place. As at December 31, 2014, Redwater Partnership had borrowings of $913 million under the syndicated credit facility.

In addition, during 2014, Redwater Partnership issued $500 million of 3.20% series A senior secured bonds due July 2024 and $500 million of 4.05% series B senior secured bonds due July 2044. Subsequent to December 31, 2014, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The assets, liabilities, partners' equity and equity loss related to Redwater Partnership and the Company's 50% interest at December 31, 2014 were comprised as follows:

		Redwater Partnership 100% interest		Company 50% interest
Current assets	$	132	$	66
Non-current assets	$	3,062	$	1,531
Current liabilities	$	454	$	227
Non-current liabilities	$	2,144	$	1,072
Partners' equity	$	596	$	298
Equity loss	$	16	$	8

9. LONG-TERM DEBT

		2014		2013
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,404**	$	1,246
Medium-term notes				
4.95% debentures due June 1, 2015		**400**		400
3.05% debentures due June 19, 2019		**500**		500
2.60% debentures due December 3, 2019		**500**		–
2.89% debentures due August 14, 2020		**500**		500
3.55% debentures due June 3, 2024		**500**		–
		4,804		2,646
US dollar denominated debt, unsecured				
Commercial paper (US$500 million)		**580**		532
US dollar debt securities				
1.45% due November 14, 2014 (2014 – US$nil; 2013 – US$500 million)		**–**		532
4.90% due December 1, 2014 (2014 – US$nil; 2013 – US$350 million)		**–**		372
Three-month LIBOR plus 0.375% due March 30, 2016 (2014 – US$500 million, 2013 – US$nil)		**580**		–
6.00% due August 15, 2016 (US$250 million)		**290**		266
5.70% due May 15, 2017 (US$1,100 million)		**1,276**		1,169
1.75% due January 15, 2018 (2014 – US$600 million; 2013 – US$nil)		**696**		–
5.90% due February 1, 2018 (US$400 million)		**464**		426
3.45% due November 15, 2021 (US$500 million)		**580**		532
3.80% due April 15, 2024 (US$500 million, 2013 – US$nil)		**580**		–
3.90% due February 1, 2025 (2014 – US$600 million; 2013 – US$nil)		**696**		–
7.20% due January 15, 2032 (US$400 million)		**464**		426
6.45% due June 30, 2033 (US$350 million)		**406**		372
5.85% due February 1, 2035 (US$350 million)		**406**		372
6.50% due February 15, 2037 (US$450 million)		**523**		479
6.25% due March 15, 2038 (US$1,100 million)		**1,276**		1,169
6.75% due February 1, 2039 (US$400 million)		**464**		426
Less: original issue discount on US dollar debt securities (1)		**(21)**		(18)
		9,260		7,055
Fair value impact of interest rate swaps on US dollar debt securities (2)		**–**		9
		9,260		7,064
Long-term debt before transaction costs		**14,064**		9,710
Less: transaction costs (1) (3)		**(62)**		(49)
		14,002		9,661
Less: current portion of commercial paper		**580**		532
current portion of long-term debt (1) (2) (3)		**400**		912
	$	**13,022**	$	8,217

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying amount of the outstanding debt.
(2) The carrying amount of US$350 million of 4.90% notes repaid December 2014 was adjusted by $9 million at December 31, 2013 to reflect the fair value impact of hedge accounting.
(3) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

BANK CREDIT FACILITIES AND COMMERCIAL PAPER

As at December 31, 2014, the Company had in place bank credit facilities of $5,627 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing March 2016, subsequently extended to January 2017;
- a $1,500 million revolving syndicated credit facility maturing June 2016;
- a $3,000 million revolving syndicated credit facility maturing June 2017; and,
- a £15 million demand credit facility related to the Company's North Sea operations.

Each of the $1,500 million and $3,000 million facilities is extendible annually for one-year periods at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

In connection with the agreement to acquire certain producing Canadian crude oil and natural gas properties (refer to note 7), the Company arranged a $1,000 million unsecured non-revolving bank credit facility. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2014, the Company had $1,000 million outstanding under this facility.

Subsequent to December 31, 2014 the existing $1,000 million non-revolving term credit facility was extended and now matures January 2017. In addition the Company entered into a new $1,500 million non-revolving three-year term credit facility maturing April 2018. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US$1,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2014, was 2.2% (December 31, 2013 – 1.9%), and on long-term debt outstanding for the year ended December 31, 2014 was 3.9% (December 31, 2013 – 4.4%).

At December 31, 2014 letters of credit and guarantees aggregating $359 million, including a $39 million financial guarantee related to Horizon and $214 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

MEDIUM-TERM NOTES

During 2014, the Company issued $500 million of 2.60% medium-term notes due December 2019 and $500 million of 3.55% medium-term notes due June 2024. After issuing these securities, the Company has $2,000 million remaining on its outstanding $3,000 million base shelf prospectus that allows for the issue of medium-term notes in Canada, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

During 2013, the Company repaid $400 million of 4.50% medium-term notes and issued $500 million of 2.89% medium-term notes due August 2020 under a previous base shelf prospectus.

US DOLLAR DEBT SECURITIES

During 2014, the Company issued US$500 million of three-month LIBOR plus 0.375% notes due March 2016, and concurrently entered into cross currency swaps to fix the foreign currency exchange rate risk at three-month CDOR plus 0.309% and $555 million (note 17). In addition, the Company issued US$500 million of 3.80% notes due April 2024, US$600 million of 1.75% notes due January 2018, and US$600 million of 3.90% notes due February 2025.

After issuing these securities, the Company has US$800 million remaining on its outstanding US$3,000 million base shelf prospectus that allows for the issue of US dollar debt securities in the United States, which expires in December 2015. If issued, these securities will bear interest as determined at the date of issuance.

During 2014, the Company repaid US$500 million of 1.45% notes and US$350 million of 4.90% notes. (2013 – US$400 million of 5.15% notes).

SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year		Repayment
2015	$	980
2016	$	2,397
2017	$	2,153
2018	$	1,160
2019	$	1,000
Thereafter	$	6,395

10. OTHER LONG-TERM LIABILITIES

		2014		2013
Asset retirement obligations	**$**	**4,221**	$	4,162
Share-based compensation		**203**		260
Risk management (note 17)		**–**		136
Other		**70**		65
		4,494		4,623
Less: current portion		**319**		275
	$	**4,175**	$	4,348

ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.6% (2013 – 5.0%; 2012 – 4.3%). Reconciliations of the discounted asset retirement obligations were as follows:

		2014		2013		2012
Balance – beginning of year	**$**	**4,162**	$	4,266	$	3,577
Liabilities incurred		**41**		62		51
Liabilities acquired		**404**		131		12
Liabilities settled		**(346)**		(207)		(204)
Asset retirement obligation accretion		**193**		171		151
Revision of cost, inflation rates and timing estimates		**(907)**		375		384
Change in discount rate		**558**		(723)		315
Foreign exchange adjustments		**116**		87		(20)
Balance – end of year		**4,221**		4,162		4,266
Less: current portion		**121**		–		–
	$	**4,100**	$	4,162	$	4,266

SEGMENTED ASSET RETIREMENT OBLIGATIONS

		2014		2013
Exploration and Production				
North America	**$**	**2,012**	$	1,707
North Sea		**1,169**		1,090
Offshore Africa		**255**		225
Oil Sands Mining and Upgrading		**783**		1,138
Midstream		**2**		2
	$	**4,221**	$	4,162

SHARE-BASED COMPENSATION

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

		2014		2013		2012
Balance – beginning of year	**$**	**260**	$	154	$	432
Share-based compensation expense (recovery)		**66**		135		(214)
Cash payment for stock options surrendered		**(8)**		(4)		(7)
Transferred to common shares		**(129)**		(50)		(45)
Capitalized to (recovered from) Oil Sands Mining and Upgrading		**14**		25		(12)
Balance – end of year		**203**		260		154
Less: current portion		**158**		216		129
	$	**45**	$	44	$	25

The share-based compensation liability of $203 million at December 31, 2014 (2013 – $260 million; 2012 – $154 million) was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

	2014	2013	2012
Fair value	**$ 5.51**	$ 7.08	$ 4.60
Share price	**$ 35.92**	$ 35.94	$ 28.64
Expected volatility	**25.1%**	27.2%	32.6%
Expected dividend yield	**2.5%**	2.2%	1.5%
Risk free interest rate	**1.2%**	1.5%	1.3%
Expected forfeiture rate	**4.7%**	4.6%	4.2%
Expected stock option life (1)	**4.5 years**	4.5 years	4.5 years

(1) At original time of grant.

The intrinsic value of vested stock options at December 31, 2014 was $40 million (2013 – $72 million; 2012 – $36 million).

11. INCOME TAXES

The provision for income tax was as follows:

	2014	2013	2012
Current corporate income tax – North America	**$ 702**	$ 544	$ 366
Current corporate income tax – North Sea	**(68)**	23	115
Current corporate income tax – Offshore Africa (1)	**43**	202	206
Current PRT (2) (recovery) expense – North Sea	**(273)**	(56)	44
Other taxes	**23**	22	16
Current income tax expense	**427**	735	747
Deferred corporate income tax expense	**681**	163	–
Deferred PRT (2) expense (recovery) – North Sea	**126**	(132)	(30)
Deferred income tax expense (recovery)	**807**	31	(30)
Income tax expense	**$ 1,234**	$ 766	$ 717

(1) Includes current income taxes relating to disposition of properties in 2013.
(2) Petroleum Revenue Tax.

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2014	2013	2012
Canadian statutory income tax rate	**25.1%**	25.1%	25.1%
Income tax provision at statutory rate	**$ 1,296**	$ 762	$ 655
Effect on income taxes of:			
UK PRT and other taxes	**(124)**	(166)	30
Impact of deductible UK PRT and other taxes on corporate income tax	**85**	111	(13)
Foreign and domestic tax rate differentials	**(61)**	(66)	63
Non-taxable portion of foreign exchange loss (gain)	**36**	14	(2)
Stock options exercised for common shares	**14**	33	(56)
Income tax rate and other legislative changes	**–**	15	58
Non-taxable gain on corporate acquisitions	**(34)**	(16)	–
Revisions arising from prior year tax filings	**5**	57	(10)
Other	**17**	22	(8)
Income tax expense	**$ 1,234**	$ 766	$ 717

The following table summarizes the temporary differences that give rise to the net deferred income tax liability:

	2014	2013
Deferred income tax liabilities		
Property, plant and equipment and exploration and evaluation assets	**$ 9,985**	$ 9,180
Timing of partnership items	**437**	632
Unrealized risk management activities	**120**	–
Unrealized foreign exchange gain on long-term debt	**10**	87
Deferred PRT	**37**	–
PRT deduction for corporate income tax	**–**	56
	10,589	9,955
Deferred income tax assets		
Asset retirement obligations	**(1,362)**	(1,326)
Loss carryforwards	**(117)**	(199)
Unrealized risk management activities	**–**	(23)
Deferred PRT	**–**	(90)
PRT deduction for corporate income tax	**(23)**	–
Other	**(117)**	(134)
	(1,619)	(1,772)
Net deferred income tax liability	**$ 8,970**	$ 8,183

Movements in deferred tax assets and liabilities recognized in net earnings during the year were as follows:

	2014	2013	2012
Property, plant and equipment and exploration and evaluation assets	**$ 647**	$ 250	$ 465
Timing of partnership items	**(195)**	(199)	(234)
Unrealized foreign exchange gain on long-term debt	**(77)**	(55)	(7)
Unrealized risk management activities	**142**	13	–
Asset retirement obligations	**119**	76	(238)
Loss carryforwards	**109**	25	–
Deferred PRT	**126**	(132)	(30)
PRT deduction for corporate income tax	**(77)**	78	19
Other	**13**	(25)	(5)
	$ 807	$ 31	$ (30)

The following table summarizes the movements of the net deferred income tax liability during the year:

	2014	2013	2012
Balance – beginning of year	**$ 8,183**	$ 8,174	$ 8,221
Deferred income tax expense (recovery)	**807**	31	(30)
Deferred income tax expense included in other comprehensive income	**1**	–	4
Foreign exchange adjustments	**70**	53	(21)
Business combinations	**(91)**	(75)	–
Balance – end of year	**$ 8,970**	$ 8,183	$ 8,174

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

During 2013, the Government of British Columbia substantively enacted legislation to increase its provincial corporate income tax rate effective April 1, 2013. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $15 million.

During 2012, the UK government enacted legislation to restrict the combined corporate and supplementary income tax relief on UK North Sea decommissioning expenditures to 50%. As a result of the income tax rate change, the Company's deferred income tax liability was increased by $58 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. The Company has not recognized deferred income tax assets with respect to taxable capital loss carryforwards in excess of $1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to North American tax pools of approximately $700 million, which can only be claimed against income from certain oil and gas properties.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

12. SHARE CAPITAL

AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

ISSUED

	2014			2013		
Common shares	**Number of shares** (thousands)		**Amount**	Number of shares (thousands)		Amount
Balance – beginning of year	**1,087,322**	**$**	**3,854**	1,092,072	$	3,709
Issued upon exercise of stock options	**14,610**		**488**	5,415		130
Previously recognized liability on stock options exercised for common shares	**–**		**129**	–		50
Purchase of common shares under Normal Course Issuer Bid	**(10,095)**		**(39)**	(10,165)		(35)
Balance – end of year	**1,091,837**	**$**	**4,432**	1,087,322	$	3,854

PREFERRED SHARES

Preferred shares are issuable in a series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions and conditions attached to the shares will be determined by the Board of Directors of the Company.

DIVIDEND POLICY

The Company has paid regular quarterly dividends in January, April, July and October of each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 4 2015, the Board of Directors approved a quarterly dividend of $0.23 per common share, beginning with the dividend payable on April 1, 2015 ($0.225 per common share, approved on March 5, 2014 beginning with the dividend payable on April 1, 2014). In 2013, the Board of Directors approved a dividend of $0.20 per common share on November 5, 2013, beginning with the dividend payable on January 1, 2014 ($0.125 per common share, approved on March 6, 2013, beginning with the dividend payable on April 1, 2013). In 2012, the Board of Directors approved a quarterly dividend of $0.105 per common share, beginning with the dividend payable on April 1, 2012.

NORMAL COURSE ISSUER BID

In 2014, the Company announced a Normal Course Issuer Bid to purchase, through the facilities of the Toronto Stock Exchange and the New York Stock Exchange, during the twelve month period commencing April 2014 and ending April 2015, up to 54,596,899 common shares. The Company's Normal Course Issuer Bid announced in 2013 expired April 2014.

During 2014, the Company purchased for cancellation 10,095,000 common shares (2013 – 10,164,800 common shares; 2012 – 11,012,700 common shares) at a weighted average price of $44.85 per common share (2013 – $31.46 per common share; 2012 – $28.91 per common share), for a total cost of $453 million (2013 – $320 million; 2012 – $318 million). Retained earnings were reduced by $414 million (2013 – $285 million; 2012 – $281 million), representing the excess of the purchase price of common shares over their average carrying value.

STOCK OPTIONS

The Company's Option Plan provides for the granting of stock options to employees. Stock options granted under the Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender of the stock option.

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2014 and 2013:

	2014			2013		
	Stock options (thousands)		**Weighted average exercise price**	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**72,741**	**$**	**34.36**	73,747	$	34.13
Granted	**18,517**	**$**	**38.70**	17,823	$	32.51
Surrendered for cash settlement	**(1,047)**	**$**	**33.74**	(401)	$	23.83
Exercised for common shares	**(14,610)**	**$**	**33.40**	(5,415)	$	24.03
Forfeited	**(3,893)**	**$**	**36.00**	(13,013)	$	34.93
Outstanding – end of year	**71,708**	**$**	**35.60**	72,741	$	34.36
Exercisable – end of year	**23,717**	**$**	**36.27**	26,632	$	35.27

The range of exercise prices of stock options outstanding and exercisable at December 31, 2014 was as follows:

	Stock options outstanding				**Stock options exercisable**		
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)		**Weighted average exercise price**	**Stock options exercisable** (thousands)		**Weighted average exercise price**
\$23.87-\$24.99	50	0.21	$	23.87	50	$	23.87
\$25.00-\$29.99	11,493	3.22	$	28.26	3,584	$	28.24
\$30.00-\$34.99	21,378	3.20	$	33.50	6,685	$	34.20
\$35.00-\$39.99	24,136	3.43	$	36.48	7,166	$	36.97
\$40.00-\$44.99	12,939	2.80	$	42.75	5,864	$	42.24
\$45.00-\$45.09	1,712	4.08	$	45.07	368	$	45.05
	71,708	3.23	$	35.60	23,717	$	36.27

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

		2014		2013
Derivative financial instruments designated as cash flow hedges	**$**	**94**	$	81
Foreign currency translation adjustment		**(43)**		(39)
	$	**51**	$	42

14. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2014, the ratio was within the target range at 33%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

		2014		2013
Long-term debt [(1)]	**$**	**14,002**	$	9,661
Total shareholders' equity	**$**	**28,891**	$	25,772
Debt to book capitalization		**33%**		27%

(1) Includes the current portion of long-term debt.

15. NET EARNINGS PER COMMON SHARE

		2014		2013		2012
Weighted average common shares outstanding – basic (thousands of shares)		**1,091,754**		1,088,682		1,097,084
Effect of dilutive stock options (thousands of shares)		**5,068**		1,859		2,435
Weighted average common shares outstanding – diluted (thousands of shares)		**1,096,822**		1,090,541		1,099,519
Net earnings	**$**	**3,929**	$	2,270	$	1,892
Net earnings per common share – basic	**$**	**3.60**	$	2.08	$	1.72
– diluted	**$**	**3.58**	$	2.08	$	1.72

In 2014, the Company excluded 30,678,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share.

16. INTEREST AND OTHER FINANCING EXPENSE

		2014		2013		2012
Interest and other financing expense:						
Long-term debt	**$**	**542**	$	457	$	464
Other (1)		**(7)**		(2)		(1)
		535		455		463
Less: amounts capitalized on qualifying assets		**204**		175		98
Total interest and other financing expense		**331**		280		365
Total interest income		**(8)**		(1)		(1)
Net interest and other financing expense	**$**	**323**	$	279	$	364

(1) Includes the fair value impact of interest rate swaps on US dollar debt securities.

17. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

2014

Asset (liability)		**Financial assets at amortized cost**		**Fair value through profit or loss**		**Derivatives used for hedging**		**Financial liabilities at amortized cost**		**Total**
Accounts receivable	**$**	**1,889**	**$**	**–**	**$**	**–**	**$**	**–**	**$**	**1,889**
Other long-term assets		**120**		**415**		**184**		**–**		**719**
Accounts payable		**–**		**–**		**–**		**(564)**		**(564)**
Accrued liabilities		**–**		**–**		**–**		**(3,279)**		**(3,279)**
Other long-term liabilities		**–**		**–**		**–**		**(40)**		**(40)**
Long-term debt (1)		**–**		**–**		**–**		**(14,002)**		**(14,002)**
	$	**2,009**	**$**	**415**	**$**	**184**	**$**	**(17,885)**	**$**	**(15,277)**

2013

Asset (liability)		Financial assets at amortized cost		Fair value through profit or loss		Derivatives used for hedging		Financial liabilities at amortized cost		Total
Accounts receivable	$	1,427	$	–	$	–	$	–	$	1,427
Accounts payable		–		–		–		(637)		(637)
Accrued liabilities		–		–		–		(2,519)		(2,519)
Other long-term liabilities		–		(39)		(97)		(56)		(192)
Long-term debt (1)		–		–		–		(9,661)		(9,661)
	$	1,427	$	(39)	$	(97)	$	(12,873)	$	(11,582)

(1) Includes the current portion of long-term debt.

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt as noted below. The fair values of the Company's recurring other long-term assets (liabilities) and fixed rate long-term debt are outlined below:

		2014						
		Carrying amount				**Fair value**		
Asset (liability) (1) (2)				**Level 1**		**Level 2**		**Level 3**
Other long-term assets (3)	**$**	**719**	**$**	**–**	**$**	**599**	**$**	**120**
Fixed rate long-term debt (4) (5)		**(11,018)**		**(11,855)**		**–**		**–**
	$	**(10,299)**	**$**	**(11,855)**	**$**	**599**	**$**	**120**

		2013						
		Carrying amount				Fair value		
Asset (liability) (1) (2)				Level 1		Level 2		Level 3
Other long-term liabilities	$	(136)	$	–	$	(136)	$	–
Fixed rate long-term debt (4) (5) (6)		(7,883)		(8,628)		–		–
	$	(8,019)	$	(8,628)	$	(136)	$	–

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).
(2) There were no transfers between Level 1, 2 and 3 financial instruments.
(3) The fair value of North West Redwater Partnership subordinated debt is based on the present value of future cash receipts.
(4) The fair value of fixed rate long-term debt has been determined based on quoted market prices.
(5) Includes the current portion of fixed rate long-term debt.
(6) The carrying amount of US$350 million of 4.90% notes repaid December 2014 was adjusted by $9 million at December 31, 2013 to reflect the fair value impact of hedge accounting.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)		**2014**		2013
Derivatives held for trading				
Crude oil price collars	**$**	**410**	$	(33)
Crude oil WCS (1) differential swaps		**(16)**		–
Foreign currency forward contracts		**21**		(3)
Natural gas AECO basis swaps		**–**		(1)
Natural gas AECO put options, net of put premium financing obligations		**–**		(2)
Cash flow hedges				
Foreign currency forward contracts		**11**		(1)
Cross currency swaps		**173**		(96)
	$	**599**	$	(136)
Included within:				
Current portion of other long-term assets (liabilities)	**$**	**436**	$	(38)
Other long-term assets (liabilities)		**163**		(98)
	$	**599**	$	(136)

(1) Western Canadian Select.

During 2014, the Company recognized a loss of $3 million (2013 – gain of $4 million; 2012 – gain of $1 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 1 and Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

RISK MANAGEMENT

The Company uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The changes in estimated fair values of derivative financial instruments included in the risk management asset (liability) were recognized in the financial statements as follows:

Asset (liability)		**2014**		2013
Balance – beginning of year	**$**	**(136)**	$	(257)
Cost of outstanding put options		**–**		9
Net change in fair value of outstanding derivative financial instruments				
Risk management activities		**451**		(39)
Foreign exchange		**270**		165
Other comprehensive income		**14**		(5)
		599		(127)
Add: put premium financing obligations (1)		**–**		(9)
Balance – end of year		**599**		(136)
Less: current portion		**436**		(38)
	$	**163**	$	(98)

(1) The Company negotiated payment of put option premiums with various counterparties at the time of actual settlement of the respective options. These obligations are reflected in the 2013 risk management liability.

Net (gains) losses from risk management activities for the years ended December 31 were as follows:

		2014		2013		2012
Net realized risk management (gain) loss	**$**	**(349)**	$	(116)	$	162
Net unrealized risk management (gain) loss		**(451)**		39		(42)
	$	**(800)**	$	(77)	$	120

FINANCIAL RISK FACTORS

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2014, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Price collars	Jan 2015 – Dec 2015	50,000 bbl/d	US$80.00 – US$120.52	Brent
WCS differential swaps	Jan 2015 – Mar 2015	30,000 bbl/d	US$21.49	WCS

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2014, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2014, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jan 2015 – Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR (1) plus 0.309%
	Jan 2015 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2015 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2015 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2015 – Mar 2038	US$550	1.170	6.25%	5.76%

(1) Canadian Dealer Offered Rate ("CDOR").

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2014 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2014, the Company had US$1,766 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$500 million designated as cash flow hedges.

Financial instrument sensitivities

The following table summarizes the annualized sensitivities of the Company's 2014 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2014, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those sensitivities disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

Increase (decrease)	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase Brent US$1.00/bbl	$ (13)	$ –
Decrease Brent US$1.00/bbl	$ 13	$ –
Increase WCS US$1.00/bbl	$ 2	$ –
Decrease WCS US$1.00/bbl	$ (2)	$ –
Interest rate risk		
Increase interest rate 1%	$ (14)	$ (2)
Decrease interest rate 1%	$ 14	$ (1)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (48)	$ –
Decrease exchange rate by US$0.01	$ 47	$ –

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2014, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions and other entities. At December 31, 2014, the Company had net risk management assets of $622 million with specific counterparties related to derivative financial instruments (December 31, 2013 – $nil).

The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 564	$ –	$ –	$ –
Accrued liabilities	$ 3,279	$ –	$ –	$ –
Other long-term liabilities	$ 40	$ –	$ –	$ –
Long-term debt (1)	$ 980	$ 2,397	$ 4,313	$ 6,395

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts or transaction costs.

18. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2015	2016	2017	2018	2019	Thereafter
Product transportation and pipeline	$ 442	$ 334	$ 301	$ 268	$ 237	$ 1,512
Offshore equipment operating leases and offshore drilling	$ 341	$ 92	$ 66	$ 59	$ 19	$ –
Office leases	$ 42	$ 42	$ 44	$ 46	$ 47	$ 284
Other	$ 204	$ 125	$ 40	$ 1	$ –	$ –

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

19. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

		2014		2013		2012
Changes in non-cash working capital						
Accounts receivable	**$**	**(456)**	$	(243)	$	869
Inventory		**(31)**		(76)		(9)
Prepaids and other		**(30)**		(14)		(8)
Accounts payable		**(70)**		175		(64)
Accrued liabilities		**741**		127		(138)
Current income tax assets (liabilities)		**(586)**		94		(65)
Net changes in non-cash working capital	**$**	**(432)**	$	63	$	585
Relating to:						
Operating activities	**$**	**(744)**	$	(33)	$	447
Financing activities		**(22)**		(23)		(37)
Investing activities		**334**		119		175
	$	**(432)**	$	63	$	585

		2014		2013		2012
Expenditures on exploration and evaluation assets	**$**	**1,190**	$	119	$	309
Net proceeds on sale of exploration and evaluation assets		**–**		(263)		–
Expenditures on property, plant and equipment		**10,252**		7,249		5,804
Net proceeds on sale of property, plant and equipment		**(44)**		(38)		(9)
Net expenditures on exploration and evaluation assets and property, plant and equipment	**$**	**11,398**	$	7,067	$	6,104

20. SEGMENTED INFORMATION

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production and marketing of crude oil, natural gas liquids and natural gas.

The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. The bitumen in the segment is recovered through mining operations.

Midstream activities include the Company's pipeline operations, an electricity co-generation system and Redwater Partnership. Production activities that are not included in the above segments are reported in the segmented information as other. Inter-segment eliminations include internal transportation and electricity charges.

	Exploration and Production								
	North America			North Sea			Offshore Africa		
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Segmented product sales	**$15,963**	$ 12,659	$ 11,607	**$ 701**	$ 805	$ 928	**$ 503**	$ 824	$ 773
Less: royalties	**(2,159)**	(1,477)	(1,268)	**(2)**	(2)	(2)	**(43)**	(137)	(199)
Segmented revenue	**13,804**	11,182	10,339	**699**	803	926	**460**	687	574
Segmented expenses									
Production	**2,924**	2,351	2,165	**496**	431	402	**212**	191	163
Transportation and blending	**3,228**	2,939	2,735	**5**	6	10	**1**	1	1
Depletion, depreciation and amortization	**3,901**	3,568	3,413	**269**	552	296	**105**	134	165
Asset retirement obligation accretion	**98**	92	85	**38**	35	27	**10**	10	7
Realized risk management activities	**(349)**	(116)	162	**–**	–	–	**–**	–	–
Gain on corporate acquisitions/ disposition of properties	**(137)**	(65)	–	**–**	–	–	**–**	(224)	–
Equity loss from investment	**–**	–	–	**–**	–	–	**–**	–	–
Total segmented expenses	**9,665**	8,769	8,560	**808**	1,024	735	**328**	112	336
Segmented earnings (loss) before the following	**$ 4,139**	$ 2,413	$ 1,779	**$ (109)**	$ (221)	$ 191	**$ 132**	$ 575	$ 238
Non–segmented expenses									
Administration									
Share-based compensation									
Interest and other financing expense									
Unrealized risk management activities									
Foreign exchange loss (gain)									
Total non–segmented expenses									
Earnings before taxes									
Current income tax expense									
Deferred income tax expense (recovery)									
Net earnings									

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenue and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

Operating segments are reported in a manner consistent with the internal reporting provided to the Company's chief operating decision makers.

Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012	**2014**	2013	2012
$ 4,095	$ 3,631	$ 2,871	**$ 120**	$ 110	$ 93	**$ (81)**	$ (84)	$ (77)	**$21,301**	$ 17,945	$ 16,195
(234)	(184)	(137)	**–**	–	–	**–**	–	–	**(2,438)**	(1,800)	(1,606)
3,861	3,447	2,734	**120**	110	93	**(81)**	(84)	(77)	**18,863**	16,145	14,589
1,609	1,567	1,504	**34**	34	29	**(10)**	(15)	(14)	**5,265**	4,559	4,249
75	63	61	**–**	–	–	**(77)**	(71)	(55)	**3,232**	2,938	2,752
596	582	447	**9**	8	7	**–**	–	–	**4,880**	4,844	4,328
47	34	32	**–**	–	–	**–**	–	–	**193**	171	151
–	–	–	**–**	–	–	**–**	–	–	**(349)**	(116)	162
–	–	–	**–**	–	–	**–**	–	–	**(137)**	(289)	–
–	–	–	**8**	4	9	**–**	–	–	**8**	4	9
2,327	2,246	2,044	**51**	46	45	**(87)**	(86)	(69)	**13,092**	12,111	11,651
$ 1,534	$ 1,201	$ 690	**$ 69**	$ 64	$ 48	**$ 6**	$ 2	$ (8)	**5,771**	4,034	2,938
									367	335	270
									66	135	(214)
									323	279	364
									(451)	39	(42)
									303	210	(49)
									608	998	329
									5,163	3,036	2,609
									427	735	747
									807	31	(30)
									$ 3,929	$ 2,270	$ 1,892

CAPITAL EXPENDITURES [1]

	2014			2013		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 1,103**	**$ (247)**	**$ 856**	$ 90	$ (84)	$ 6
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa [3]	**87**	**–**	**87**	(10)	–	(10)
	$ 1,190	**$ (247)**	**$ 943**	$ 80	$ (84)	$ (4)
Property, plant and equipment						
Exploration and Production						
North America	**$ 6,397**	**$ 399**	**$ 6,796**	$ 3,936	$ (450)	$ 3,486
North Sea	**400**	**86**	**486**	334	(35)	299
Offshore Africa	**194**	**(1)**	**193**	114	(17)	97
	6,991	**484**	**7,475**	4,384	(502)	3,882
Oil Sands Mining and Upgrading [4]	**3,110**	**(528)**	**2,582**	2,592	(189)	2,403
Midstream	**62**	**–**	**62**	197	(1)	196
Head office	**45**	**(1)**	**44**	38	–	38
	$ 10,208	**$ (45)**	**$ 10,163**	$ 7,211	$ (692)	$ 6,519

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.
(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.
(3) The above noted figures in 2013 do not include the impact of a pre-tax gain on sale of exploration and evaluation assets totaling $224 million on the Company's disposition of a 50% interest in its exploration right in South Africa.
(4) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

SEGMENTED ASSETS

	2014	2013
Exploration and Production		
North America	**$ 34,382**	$ 29,234
North Sea	**2,711**	1,964
Offshore Africa	**1,214**	981
Other	**18**	25
Oil Sands Mining and Upgrading	**20,702**	18,604
Midstream	**1,048**	841
Head office	**125**	105
	$ 60,200	$ 51,754

21. REMUNERATION OF DIRECTORS AND SENIOR MANAGEMENT

REMUNERATION OF NON-MANAGEMENT DIRECTORS

		2014		2013		2012
Fees earned	**$**	**3**	$	2	$	2

REMUNERATION OF SENIOR MANAGEMENT (1)

		2014		2013		2012
Salary	**$**	**3**	$	3	$	2
Common stock option based awards		**8**		11		12
Annual incentive plans		**4**		3		3
Long-term incentive plans		**17**		14		9
Other compensation		**–**		1		–
	$	**32**	$	32	$	26

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.

SUPPLEMENTARY OIL AND GAS INFORMATION (unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards ("IFRS").

For the years ended December 31, 2014, 2013, 2012 and 2011 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences to the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2014, 2013, 2012, and 2011 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2014 reserves for SEC requirements.

Crude Oil and NGLs					Natural Gas		
WTI Cushing Oklahoma (US$/bbl)	WCS (C$/bbl)	Canadian Light Sweet (C$/bbl)	North Sea Brent (US$/bbl)	Edmonton C5+ (C$/bbl)	Henry Hub Louisiana (US$/MMBtu)	AECO (C$/MMBtu)	BC Westcoast Station 2 (C$/MMBtu)
94.99	82.96	94.84	101.80	104.52	4.30	4.60	4.45

A foreign exchange rate of US$1.00/C$1.099 was used in the 2014 evaluation, determined on the same basis as the 12-month average price.

NET PROVED CRUDE OIL AND NATURAL GAS RESERVES

The Company retains Independent Qualified Reserves Evaluators to evaluate the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas and natural gas liquids ("NGLs") reserves.

- For the years ended December 31, 2014, 2013, 2012, and 2011, the reports by GLJ Petroleum Consultants Ltd. covered 100% of the Company's SCO reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2014, 2013, 2012, and 2011, the reports by Sproule Associates Limited and Sproule International Limited covered 100% of the Company's crude oil, bitumen, natural gas and NGLs reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, are the estimated quantities of oil and gas that by analysis of geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Developed crude oil and natural gas reserves are reserves of any category that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Undeveloped crude oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2014, 2013, 2012, and 2011:

	North America						
Crude Oil and NGLs (MMbbl)	**Synthetic Crude Oil**	**Bitumen**[1]	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2011	1,836	869	366	3,071	244	88	3,403
Extensions and discoveries	–	90	5	95	–	–	95
Improved recovery	–	25	9	34	–	1	35
Purchases of reserves in place	–	–	2	2	–	–	2
Sales of reserves in place	–	–	–	–	–	–	–
Production	(30)	(70)	(31)	(131)	(7)	(5)	(143)
Economic revisions due to prices	34	6	(20)	20	4	–	24
Revisions of prior estimates	134	79	39	252	(6)	1	247
Reserves, December 31, 2012	1,974	999	370	3,343	235	85	3,663
Extensions and discoveries	–	76	13	89	–	–	89
Improved recovery	–	9	7	16	–	–	16
Purchases of reserves in place	–	–	8	8	6	–	14
Sales of reserves in place	–	–	–	–	–	–	–
Production	(35)	(71)	(33)	(139)	(7)	(5)	(151)
Economic revisions due to prices	(10)	(1)	4	(7)	–	(2)	(9)
Revisions of prior estimates	(4)	56	11	63	(2)	2	63
Reserves, December 31, 2013	1,925	1,068	380	3,373	232	80	3,685
Extensions and discoveries	**–**	**112**	**11**	**123**	**–**	**–**	**123**
Improved recovery	**–**	**10**	**29**	**39**	**–**	**–**	**39**
Purchases of reserves in place	**–**	**–**	**54**	**54**	**–**	**–**	**54**
Sales of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Production	**(38)**	**(76)**	**(40)**	**(154)**	**(6)**	**(4)**	**(164)**
Economic revisions due to prices	**(89)**	**11**	**–**	**(78)**	**(9)**	**1**	**(86)**
Revisions of prior estimates	**(18)**	**23**	**47**	**52**	**(6)**	**–**	**46**
Reserves, December 31, 2014	**1,780**	**1,148**	**481**	**3,409**	**211**	**77**	**3,697**
Net proved developed reserves							
December 31, 2011	1,588	269	269	2,126	78	61	2,265
December 31, 2012	1,612	348	295	2,255	66	55	2,376
December 31, 2013	1,621	431	298	2,350	59	30	2,439
December 31, 2014	**1,631**	**401**	**358**	**2,390**	**39**	**21**	**2,450**

(1) Bitumen as defined by the SEC, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal and primary heavy crude oil reserves have been classified as bitumen.

Natural Gas (Bcf)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Net Proved Reserves				
Reserves, December 31, 2011	3,499	97	54	3,650
Extensions and discoveries	50	–	–	50
Improved recovery	11	–	–	11
Purchases of reserves in place	34	–	–	34
Sales of reserves in place	(1)	–	–	(1)
Production	(429)	(1)	(6)	(436)
Economic revisions due to prices	(596)	1	–	(595)
Revisions of prior estimates	79	(14)	–	65
Reserves, December 31, 2012	2,647	83	48	2,778
Extensions and discoveries	126	–	–	126
Improved recovery	62	–	–	62
Purchases of reserves in place	99	14	–	113
Sales of reserves in place	(1)	–	–	(1)
Production	(394)	(1)	(8)	(403)
Economic revisions due to prices	489	–	(2)	487
Revisions of prior estimates	206	(4)	(1)	201
Reserves, December 31, 2013	3,234	92	37	3,363
Extensions and discoveries	**119**	**–**	**–**	**119**
Improved recovery	**443**	**–**	**–**	**443**
Purchases of reserves in place	**1,229**	**–**	**–**	**1,229**
Sales of reserves in place	**–**	**–**	**–**	**–**
Production	**(514)**	**(2)**	**(6)**	**(522)**
Economic revisions due to prices	**576**	**(6)**	**1**	**571**
Revisions of prior estimates	**(70)**	**–**	**2**	**(68)**
Reserves, December 31, 2014	**5,017**	**84**	**34**	**5,135**
Net proved developed reserves				
December 31, 2011	2,637	60	47	2,744
December 31, 2012	2,060	58	39	2,157
December 31, 2013	2,342	72	27	2,441
December 31, 2014	**3,585**	**64**	**22**	**3,671**

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

	2014			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Proved properties	**$ 82,554**	**$ 6,182**	**$ 3,858**	**$ 92,594**
Unproved properties	**3,426**	**–**	**131**	**3,557**
	85,980	**6,182**	**3,989**	**96,151**
Less: accumulated depletion and depreciation	**(33,750)**	**(4,049)**	**(2,890)**	**(40,689)**
Net capitalized costs	**$ 52,230**	**$ 2,133**	**$ 1,099**	**$ 55,462**

	2013			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 73,176	$ 5,200	$ 3,356	$ 81,732
Unproved properties	2,570	–	39	2,609
	75,746	5,200	3,395	84,341
Less: accumulated depletion and depreciation	(29,729)	(3,467)	(2,551)	(35,747)
Net capitalized costs	$ 46,017	$ 1,733	$ 844	$ 48,594

	2012			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	$ 67,287	$ 4,574	$ 3,045	$ 74,906
Unproved properties	2,564	–	47	2,611
	69,851	4,574	3,092	77,517
Less: accumulated depletion and depreciation	(26,193)	(2,709)	(2,273)	(31,175)
Net capitalized costs	$ 43,658	$ 1,865	$ 819	$ 46,342

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

	2014			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Property acquisitions				
Proved	**$ 3,323**	**$ 1**	**$ –**	**$ 3,324**
Unproved	**873**	**–**	**–**	**873**
Exploration	**230**	**–**	**87**	**317**
Development	**6,263**	**485**	**193**	**6,941**
Costs incurred	**$ 10,689**	**$ 486**	**$ 280**	**$ 11,455**

	2013			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 250	$ 2	$ –	$ 252
Unproved	92	–	4	96
Exploration	(2)	–	25	23
Development	6,152	297	97	6,546
Costs incurred	$ 6,492	$ 299	$ 126	$ 6,917

	2012			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	$ 144	$ –	$ –	$ 144
Unproved	44	–	3	47
Exploration	251	–	11	262
Development	5,773	556	75	6,404
Costs incurred	$ 6,212	$ 556	$ 89	$ 6,857

RESULTS OF OPERATIONS FROM CRUDE OIL AND NATURAL GAS PRODUCING ACTIVITIES

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2014, 2013 and 2012 are summarized in the following tables:

	2014			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Crude oil and natural gas revenue, net of royalties and blending costs	**$ 15,385**	**$ 696**	**$ 460**	**$ 16,541**
Production	**(4,533)**	**(496)**	**(212)**	**(5,241)**
Transportation	**(593)**	**(5)**	**(1)**	**(599)**
Depletion, depreciation and amortization	**(4,497)**	**(269)**	**(105)**	**(4,871)**
Asset retirement obligation accretion	**(145)**	**(38)**	**(10)**	**(193)**
Petroleum revenue tax	**–**	**147**	**–**	**147**
Income tax	**(1,411)**	**(22)**	**(29)**	**(1,462)**
Results of operations	**$ 4,206**	**$ 13**	**$ 103**	**$ 4,322**

	2013			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 12,274	$ 726	$ 687	$ 13,687
Production	(3,918)	(436)	(191)	(4,545)
Transportation	(483)	(6)	(1)	(490)
Depletion, depreciation and amortization	(4,150)	(552)	(134)	(4,836)
Asset retirement obligation accretion	(126)	(35)	(10)	(171)
Petroleum revenue tax	–	188	–	188
Income tax	(903)	71	(88)	(920)
Results of operations	$ 2,694	$ (44)	$ 263	$ 2,913

	2012			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 10,609	$ 837	$ 574	$ 12,020
Production	(3,669)	(402)	(163)	(4,234)
Transportation	(479)	(10)	(1)	(490)
Depletion, depreciation and amortization	(3,860)	(296)	(165)	(4,321)
Asset retirement obligation accretion	(117)	(27)	(7)	(151)
Petroleum revenue tax	–	(14)	–	(14)
Income tax	(623)	(55)	(55)	(733)
Results of operations	$ 1,861	$ 33	$ 183	$ 2,077

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS FROM PROVED CRUDE OIL AND NATURAL GAS RESERVES AND CHANGES THEREIN

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the- month price for each month within the 12-month period prior to the end of the reporting period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 – "Extractive Activities – Oil and Gas":

	2014			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore Africa**	**Total**
Future cash inflows	**$ 322,100**	**$ 24,786**	**$ 8,853**	**$ 355,739**
Future production costs	**(123,055)**	**(9,708)**	**(2,171)**	**(134,934)**
Future development costs and asset retirement obligations	**(56,651)**	**(8,515)**	**(1,863)**	**(67,029)**
Future income taxes	**(24,578)**	**(4,816)**	**(1,178)**	**(30,572)**
Future net cash flows	**117,816**	**1,747**	**3,641**	**123,204**
10% annual discount for timing of future cash flows	**(67,899)**	**(813)**	**(1,672)**	**(70,384)**
Standardized measure of future net cash flows	**$ 49,917**	**$ 934**	**$ 1,969**	**$ 52,820**

	2013			
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	$ 290,892	$ 26,378	$ 9,146	$ 326,416
Future production costs	(116,984)	(9,921)	(2,560)	(129,465)
Future development costs and asset retirement obligations	(51,749)	(7,602)	(1,840)	(61,191)
Future income taxes	(20,384)	(6,586)	(1,154)	(28,124)
Future net cash flows	101,775	2,269	3,592	107,636
10% annual discount for timing of future cash flows	(65,063)	(976)	(1,755)	(67,794)
Standardized measure of future net cash flows	$ 36,712	$ 1,293	$ 1,837	$ 39,842

		2012						
(millions of Canadian dollars)		North America		North Sea		Offshore Africa		Total
Future cash inflows	$	273,167	$	26,922	$	7,985	$	308,074
Future production costs		(114,825)		(9,369)		(2,428)		(126,622)
Future development costs and asset retirement obligations		(49,226)		(7,032)		(1,640)		(57,898)
Future income taxes		(16,688)		(7,662)		(949)		(25,299)
Future net cash flows		92,428		2,859		2,968		98,255
10% annual discount for timing of future cash flows		(61,878)		(1,330)		(1,313)		(64,521)
Standardized measure of future net cash flows	$	30,550	$	1,529	$	1,655	$	33,734

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)		**2014**		2013		2012
Sales of crude oil and natural gas produced, net of production costs	**$**	**(10,321)**	$	(8,525)	$	(7,895)
Net changes in sales prices and production costs		**8,575**		6,992		(7,994)
Extensions, discoveries and improved recovery		**4,428**		2,304		1,834
Changes in estimated future development costs		**(2,821)**		(1,536)		(3,492)
Purchases of proved reserves in place		**4,425**		638		83
Sales of proved reserves in place		**–**		(1)		(1)
Revisions of previous reserve estimates		**(1,306)**		622		4,266
Accretion of discount		**5,154**		4,388		5,110
Changes in production timing and other		**5,895**		2,341		946
Net change in income taxes		**(1,051)**		(1,115)		2,154
Net change		**12,978**		6,108		(4,989)
Balance – beginning of year		**39,842**		33,734		38,723
Balance – end of year	**$**	**52,820**	$	39,842	$	33,734

TEN-YEAR REVIEW

Years ended December 31	**2014**	2013	2012	2011	2010 (6)	2009 (7)	2008 (7)	2007 (7)	2006 (7)	2005 (7)
FINANCIAL INFORMATION (1) (Cdn $ millions, except per share amounts)										
Net earnings	**3,929**	2,270	1,892	2,643	1,673	1,580	4,985	2,608	2,524	1,050
Per share - basic ($/share)	**3.60**	2.08	1.72	2.41	1.54	1.46	4.61	2.42	2.35	0.98
Per share - diluted ($/share)	**3.58**	2.08	1.72	2.40	1.53	1.46	4.61	2.42	2.35	0.98
Cash flow from operations (2)	**9,587**	7,477	6,013	6,547	6,333	6,090	6,969	6,198	4,932	5,021
Per share - basic ($/share)	**8.78**	6.87	5.48	5.98	5.82	5.62	6.45	5.75	4.59	4.68
Per share - diluted ($/share)	**8.74**	6.86	5.47	5.94	5.78	5.62	6.45	5.75	4.59	4.67
Capital expenditures, net of dispositions (including business combinations)	**11,744**	7,274	6,308	6,414	5,514	2,997	7,451	6,425	12,025	4,932
Balance sheet information										
Working capital surplus (deficiency)	**(673)**	(1,574)	(1,264)	(894)	(1,200)	(514)	(28)	(1,382)	(832)	(1,774)
Exploration and evaluation assets	**3,557**	2,609	2,611	2,475	2,402	-	-	-	-	-
Property, plant and equipment, net	**52,480**	46,487	44,028	41,631	38,429	39,115	38,966	33,902	30,767	19,694
Total assets	**60,200**	51,754	48,980	47,278	42,954	41,024	42,650	36,114	33,160	21,852
Long-term debt	**14,002**	9,661	8,736	8,571	8,485	9,658	12,596	10,940	11,043	3,321
Shareholders' equity	**28,891**	25,772	24,283	22,898	20,368	19,426	18,374	13,321	10,690	8,237
SHARE INFORMATION (1)										
Common shares outstanding (thousands)	**1,091,837**	1,087,322	1,092,072	1,096,460	1,090,848	1,084,654	1,081,982	1,079,458	1,075,806	1,072,696
Weighted average shares outstanding - basic (thousands)	**1,091,754**	1,088,682	1,097,084	1,095,582	1,088,096	1,083,850	1,081,294	1,078,672	1,074,678	1,073,300
Weighted average shares outstanding - diluted (thousands)	**1,096,822**	1,090,541	1,099,519	1,102,582	1,095,648	1,083,850	1,081,294	1,078,672	1,074,678	1,076,850
Dividends declared ($/share) (8)	**0.90**	0.575	0.42	0.36	0.30	0.21	0.20	0.17	0.15	0.12
Trading statistics (1)										
TSX – C$										
Trading volume (thousands)	**717,580**	683,003	729,700	800,044	661,832	1,040,320	1,359,476	858,068	1,017,870	1,275,984
Share Price ($/share)										
High	**49.57**	36.04	41.12	50.50	45.00	39.50	55.65	40.01	36.96	31.00
Low	**31.00**	28.44	25.58	27.25	31.97	17.93	17.10	26.23	22.75	12.14
Close	**35.92**	35.94	28.64	38.15	44.35	38.00	24.38	36.29	31.08	28.82
NYSE – US$										
Trading volume (thousands)	**812,521**	645,403	844,647	937,481	759,327	1,514,614	1,934,456	972,532	803,818	503,108
Share Price ($/share)										
High	**46.65**	33.92	41.38	52.04	44.77	38.26	54.66	43.59	32.19	27.03
Low	**26.53**	26.98	25.01	25.69	30.00	13.85	13.22	22.28	20.15	9.87
Close	**30.88**	33.84	28.87	37.37	44.42	35.98	19.99	36.57	26.62	24.81
RATIOS										
Debt to book capitalization (3)	**33%**	27%	26%	27%	29%	33%	41%	45%	51%	29%
Return on average common shareholders' equity, after tax (3)	**14%**	9%	8%	12%	8%	8%	33%	22%	27%	14%
Daily production before royalties per ten thousand common shares (BOE/d) (1)	**7.2**	6.2	6.0	5.5	5.8	5.3	5.2	5.7	5.4	5.2
Total proved plus probable reserves per common share (BOE) (1)(4)	**8.1**	7.3	7.2	6.9	6.3	5.8	3.1	3.2	3.2	2.4
Net asset value ($/share) (1)(5)	**78.99**	72.41	62.38	70.37	64.58	64.92	39.89	34.47	28.21	30.22

(1) Restated to reflect two-for-one share splits in May 2004, May 2005 and May 2010.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. Cash flow from operations may not be comparable to similar measures used by other companies.

(3) Refer to the "Liquidity and Capital Resources" section of the MD&A for the definitions of these items.

(4) Based upon company gross reserves (forecast price and costs, before royalties), using year-end common shares outstanding. Excludes Horizon SCO reserves prior to 2009. Prior to 2010, Company gross reserves were prepared using constant prices and costs.

(5) Calculated as the net present value of future net revenue, before income tax, of the Company's total proved plus probable reserves prepared using forecast prices and costs discounted at 10%, as reported in the Company's AIF, with $300/acre added for core unproved property ($250/acre for core undeveloped land from 2005 to 2009, $75/acre for core undeveloped land for all years prior to 2005), less net debt and using year end common shares outstanding. Net debt is the Company's long-term debt plus/minus the working capital deficit/surplus. Excludes Horizon SCO reserves prior to 2009. Future development costs and associated material well abandonment costs have been applied against the future net revenue.

(6) 2010 comparative figures have been restated in accordance with IFRS issued at December 31, 2011.

(7) Comparative figures for years prior to 2010 are in accordance with Canadian GAAP as previously reported and may not be prepared on a basis consistent with IFRS as adopted.

(8) On March 5, 2014, the Board of Directors approved a quarterly dividend of $0.225 per common share, beginning with the dividend payable on April 1, 2014 ($0.20 per common share, approved on November 5, 2013, beginning with the dividend payable on January 1, 2014).

Years ended December 31	**2014**	2013	2012	2011	2010 (6)	2009	2008	2007	2006	2005
OPERATING INFORMATION										
Crude oil and NGLs (MMbbl) (9)										
Company net proved reserves (after royalties)										
North America	**3,380**	3,290	3,268	3,007	2,763	2,664	948	920	887	694
North Sea	**204**	224	227	228	252	240	256	310	299	290
Offshore Africa	**78**	80	85	87	101	123	142	128	130	134
	3,662	3,594	3,580	3,322	3,116	3,027	1,346	1,358	1,316	1,118
Horizon SCO (9)	**-**	-	-	-	-	-	1,946	1,761	1,596	1,626
Company net proved and probable reserves (after royalties)										
North America	**5,609**	5,135	5,119	4,777	4,293	4,172	1,599	1,545	1,502	1,035
North Sea	**308**	325	332	349	376	387	399	405	422	417
Offshore Africa	**119**	122	127	131	149	179	191	186	195	206
	6,036	5,582	5,578	5,257	4,818	4,738	2,189	2,136	2,119	1,658
Horizon SCO (9)	**-**	-	-	-	-	-	2,944	2,680	2,542	2,566
Natural gas (Bcf) (9)										
Company net proved reserves (after royalties)										
North America	**5,054**	3,684	3,540	3,778	3,638	3,027	3,523	3,521	3,705	2,741
North Sea	**83**	91	82	98	78	67	67	81	37	29
Offshore Africa	**36**	38	48	54	76	85	94	64	56	72
	5,173	3,813	3,670	3,930	3,792	3,179	3,684	3,666	3,798	2,842
Company net proved plus probable reserves (after royalties)										
North America	**6,791**	5,138	4,907	5,125	4,870	3,992	4,619	4,602	4,857	3,548
North Sea	**114**	125	102	134	107	94	94	113	93	69
Offshore Africa	**68**	70	76	83	113	124	131	88	99	110
	6,973	5,333	5,085	5,342	5,090	4,210	4,844	4,803	5,049	3,727
Total proved reserves (after royalties) (MMBOE)	**4,524**	4,230	4,191	3,977	3,748	3,557	1,960	1,969	1,949	1,592
Total proved plus probable reserves (after royalties) (MMBOE)	**7,198**	6,471	6,426	6,147	5,666	5,440	2,996	2,937	2,961	2,279
Daily production (before royalties)										
Crude oil and NGLs (Mbbl/d)										
North America - Exploration and Production	**391**	344	326	296	271	234	244	247	235	222
North America - Oil Sands Mining and Upgrading	**111**	100	86	40	91	50	-	-	-	-
North Sea	**17**	18	20	30	33	38	45	56	60	68
Offshore Africa	**12**	16	19	23	30	33	27	28	37	23
	531	478	451	389	425	355	316	331	332	313
Natural gas (MMcf/d)										
North America	**1,527**	1,130	1,198	1,231	1,217	1,287	1,472	1,643	1,468	1,416
North Sea	**7**	4	2	7	10	10	10	13	15	19
Offshore Africa	**21**	24	20	19	16	18	13	12	9	4
	1,555	1,158	1,220	1,257	1,243	1,315	1,495	1,668	1,492	1,439
Total production (before royalties) (MBOE/d)	**790**	671	655	599	632	575	565	609	581	553
Product pricing										
Average crude oil and NGLs price ($/bbl) (10)	**77.04**	73.81	72.44	79.16	65.81	57.68	82.41	55.45	53.65	46.86
Average natural gas price ($/Mcf) (10)	**4.83**	3.58	2.70	3.99	4.08	4.53	8.39	6.85	6.72	8.57
Average SCO price ($/bbl) (10)	**100.27**	100.75	90.74	101.48	77.89	70.83	-	-	-	-

(9) For the years 2014 to 2010, company net reserves were prepared using forecast prices and costs; prior to 2010, company net reserves were prepared using constant prices and costs. Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance with the SEC's Industry Guide 7. With the SEC's Final Rule in effect January 1, 2010, this SCO is now included in the Company's crude oil and natural gas reserves totals.

(10) For the years 2011 to 2014, product prices reflect realized product prices before transportation costs. Prior to 2011, product prices were reported net of transportation costs.

CORPORATE INFORMATION

BOARD OF DIRECTORS

***Catherine M. Best**, FCA, ICD.D (1)(2)
Corporate Director
Calgary, Alberta

N. Murray Edwards, O.C. (5)
President, Edco Financial Holdings Ltd.
Calgary/Banff, Alberta

***Timothy W. Faithfull** (1)(3)
Corporate Director
London, England

***Honourable Gary A. Filmon**, P.C., O.C., O.M. (1)(4)
Corporate Director
Winnipeg, Manitoba

***Christopher L. Fong** (3)(5)
Corporate Director
Calgary, Alberta

***Ambassador Gordon D. Giffin** (1)(4)
Senior Partner, McKenna Long & Aldridge LLP
Atlanta, Georgia

***Wilfred A. Gobert** (2)(4)(5)
Corporate Director
Calgary, Alberta

Steve W. Laut (3)
President,
Canadian Natural Resources Limited
Calgary, Alberta

Keith A. J. MacPhail (3)(5)
Executive Chairman
Bonavista Energy Corporation
Calgary, Alberta

***Honourable Frank J. McKenna**, P.C., O.C., O.N.B., Q.C. (2)(4)
Deputy Chair, TD Bank Group
Cap Pelé, New Brunswick

***Dr. Eldon R. Smith**, OC., M.D. (2)(3)
President, Eldon R. Smith & Associates Ltd.
Emeritus Professor of Medicine and Former Dean,
Faculty of Medicine, University of Calgary
Calgary, Alberta

***David A. Tuer** (1)(5)
Vice-Chairman and Chief Executive Officer,
Teine Energy Ltd.
Calgary, Alberta

***Annette M. Verschuren**, O.C.
Chairman and Chief Executive Officer, NRSTOR Inc.
Toronto, Ontario

OFFICERS

N. Murray Edwards
Chairman of the Board

Steve W. Laut
President

Tim S. McKay
Chief Operating Officer

Douglas A. Proll
Executive Vice-President

Lyle G. Stevens
Executive Vice-President, Canadian Conventional

Corey B. Bieber
Chief Financial Officer and Senior Vice-President, Finance

Réal M. Cusson
Senior Vice-President, Marketing

Réal J.H. Doucet
Senior Vice-President, Horizon Projects

Darren M. Fichter
Senior Vice-President, Exploitation

Peter J. Janson
Senior Vice-President, Horizon Operations

Terry J. Jocksch
Senior Vice-President, Thermal

Ronald K. Laing
Senior Vice-President, Corporate Development and Land

Paul M. Mendes
Vice-President, Legal and General Counsel

Bill R. Peterson
Senior Vice-President, Production and Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

Scott G. Stauth
Senior Vice-President, North American Operations

Bruce E. McGrath
Corporate Secretary

(1) Audit Committee member
(2) Compensation Committee member
(3) Health, Safety & Environmental Committee member
(4) Nominating, Governance & Risk Committee member
(5) Reserves Committee member
* Determined to be independent by the Nominating and Corporate Governance Committee and the Board of Directors and pursuant to the independent standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

CORPORATE OFFICES

HEAD OFFICE

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Calgary, AB T2P 4J8
Telephone: (403) 517-6700
Facsimile: (403) 517-7350
Website: www.cnrl.com

INVESTOR RELATIONS

Telephone: (403) 514-7777
Email: ir@cnrl.com

INTERNATIONAL OFFICE

CNR International (U.K.) Limited
St. Magnus House, Guild Street
Aberdeen AB11 6NJ Scotland

REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

AUDITORS

PricewaterhouseCoopers LLP
Calgary, Alberta

INDEPENDENT QUALIFIED RESERVES EVALUATORS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

Sproule International Limited
Calgary, Alberta

STOCK LISTING - CNQ

Toronto Stock Exchange
The New York Stock Exchange

COMPANY DEFINITION

Throughout the annual report, Canadian Natural Resources Limited is referred to as "us", "we", "our", "Canadian Natural", or the "Company".

CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

ABBREVIATIONS

Abbreviations can be found on page 22.

METRIC CONVERSION CHART

To convert	To	Multiply by
barrels	cubic metres	0.159
thousand cubic feet	cubic metres	28.174
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
tonnes	tons	1.102

COMMON SHARE DIVIDEND

The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid on the first day of every January, April, July and October. The following table shows the aggregate amount of the cash dividends declared per common share of the Company in each of its last three years ended December 31.

	2014	2013	2012
Cash dividends declared per common share	**$ 0.90**	$ 0.575	$ 0.42

NOTICE OF ANNUAL MEETING

Canadian Natural's Annual General Meeting of the Shareholders will be held on Thursday, May 7, 2015 at 1:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, Calgary, Alberta.

CORPORATE GOVERNANCE

Canadian Natural, as a "foreign private issuer" listed on the New York Stock Exchange ("NYSE"), is not required to comply with most of the NYSE's corporate governance standards and instead may rely on Canadian corporate governance practices. Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices.

Under NYSE rules, Canadian Natural must disclose any significant differences between its corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE's corporate governance standards. Except as described below, Canadian Natural is in compliance with the NYSE's corporate governance standards in all significant respects.

Canadian Natural follows Toronto Stock Exchange ("TSX") rules with respect to shareholder approval of equity compensation plans and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a performance share unit plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the performance share unit plan and under TSX rules the plan is not subject to shareholder approval.

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