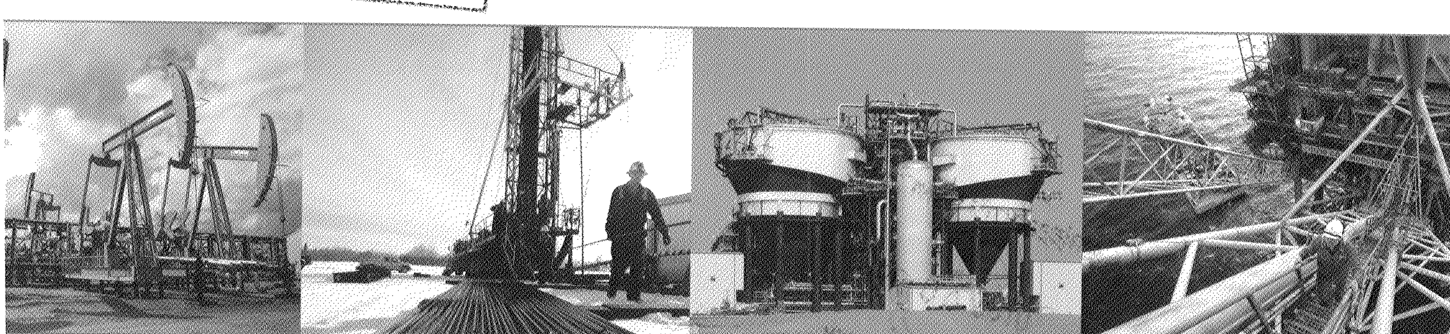
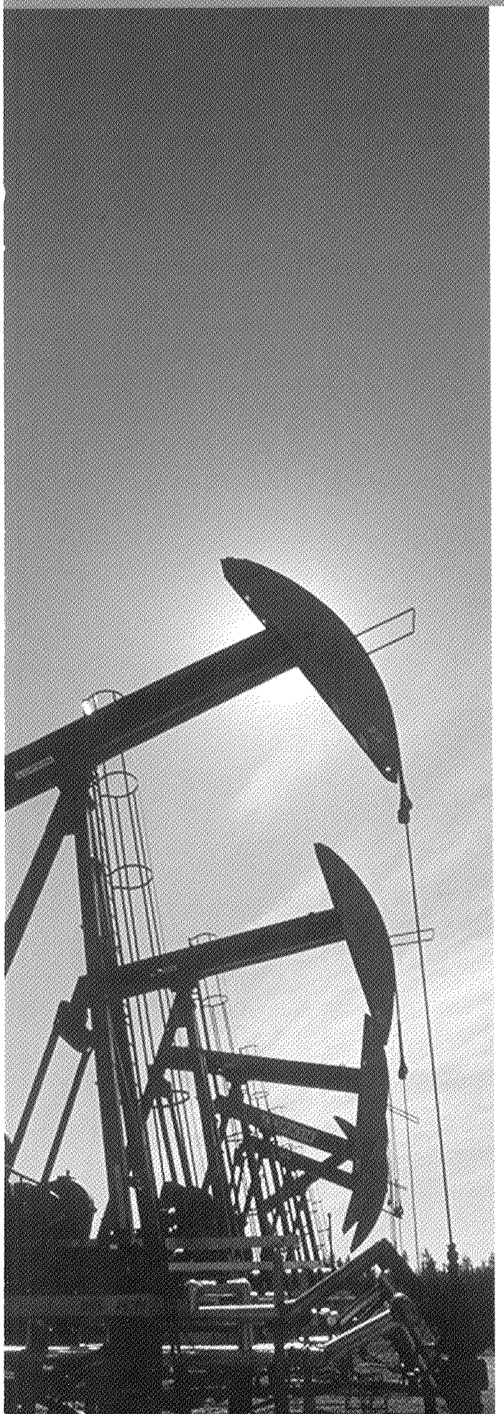
Canadian Natural



THE PREMIUM VALUE • DEFINED GROWTH • INDEPENDENT

2009 ANNUAL REPORT



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 21.

OUR BUSINESS APPROACH

Value creating principles

Canadian Natural's success results from delivering upon value creating principles that provide the foundation for how the Company operates. Management is disciplined in adhering to these principles and patient enough to execute a project only when it is economically prudent to do so.

EFFICIENCY AND EXECUTION

Drive to be the low cost producer – we believe this principle goes hand in hand with generating long-term economic returns. We cannot control commodity prices but we can influence the cost of producing them, better preparing us to drive success throughout all cycles. This is accomplished by dominating our core areas while maintaining high working interest and operatorship. We believe that assets will end up in the hands of the company with the lowest cost structure over the industry cycles.

Focus on exploitation – we believe the best place to find crude oil and natural gas is where it has already been found. Maximizing the efficiency and value of already discovered resources is a low risk approach to our business. We predominantly rely on proven technologies while continuing to evaluate technology advances. Our vast land base will continue to benefit from future improvements of resource recovery.

Augment exploitation with strategic acquisitions – we believe the reward for being a low cost producer is the ability to create value where others cannot. With our extensive land holdings, diverse asset base and strong exploitation experience, opportunities exist for value creation through acquisitions. Capturing these opportunities in the past has strengthened the Company and has added significant prospects to our inventory in both our core areas and in new strategic basins.

MAINTAIN DISCIPLINE AND STRENGTH WHILE DELIVERING ON THE DEFINED PLAN

Maintain flexibility and control allocation of capital – the ability to be flexible in the allocation of capital is crucial in our industry where economic cycles can dramatically impact the business. In 2009, this proved to be true. We endeavor to own and operate the majority of our assets which gives us the ability to control our capital allocation.

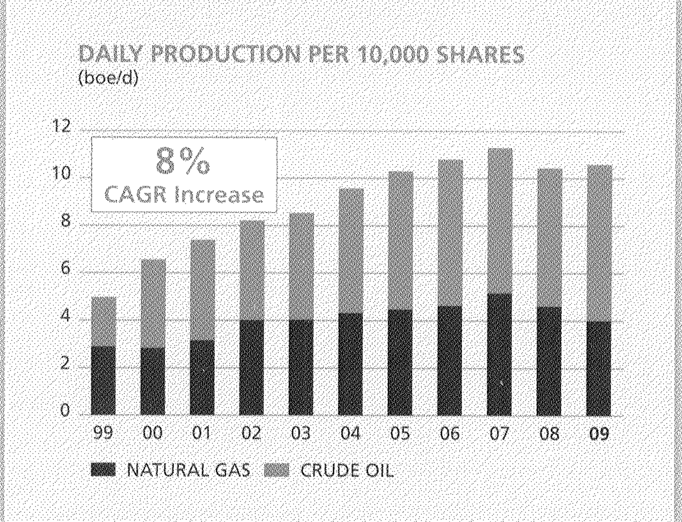
Strive for balance – the ability to persevere through economic downturns and come out stronger than when we went in is due in part to our balanced asset portfolio. With natural gas, primary heavy crude oil, thermal heavy crude oil, light crude oil and synthetic crude oil in our portfolio, we are better equipped to handle commodity price fluctuations and optimize returns. This also facilitates Management's allocation of capital to the highest return projects over the short-, mid- and long-term.

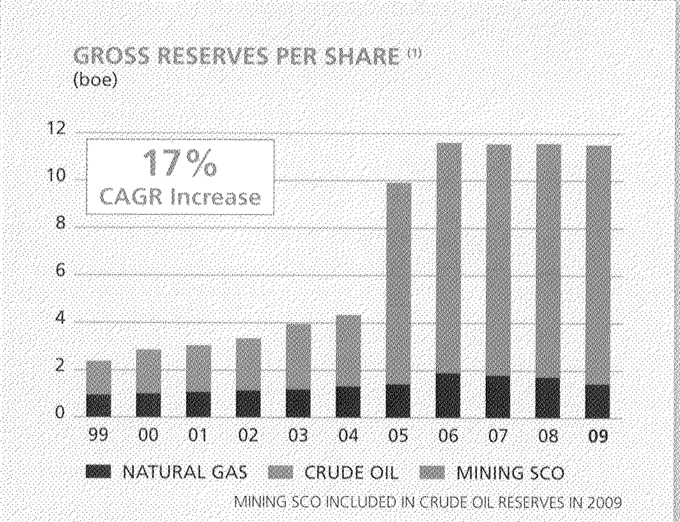
Maintain financial strength – the ability to maintain financial discipline is a key principle of how we grow the Company. Maintaining a strong balance sheet and investment grade debt ratings enable us to build a world class crude oil and natural gas company in all economic cycles.

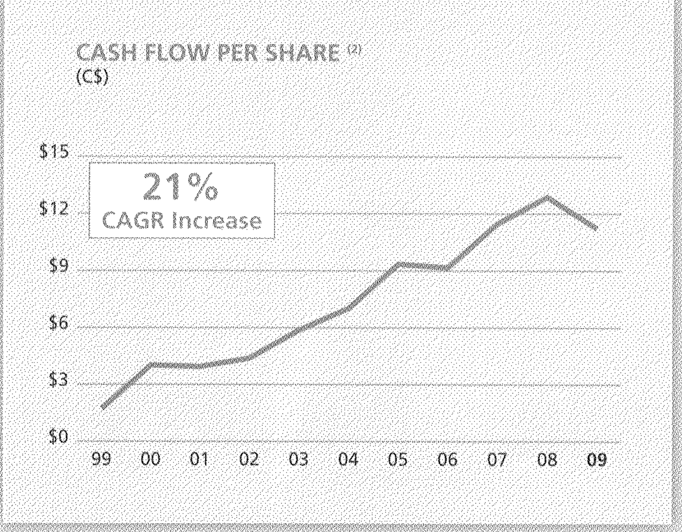
Canadian Natural

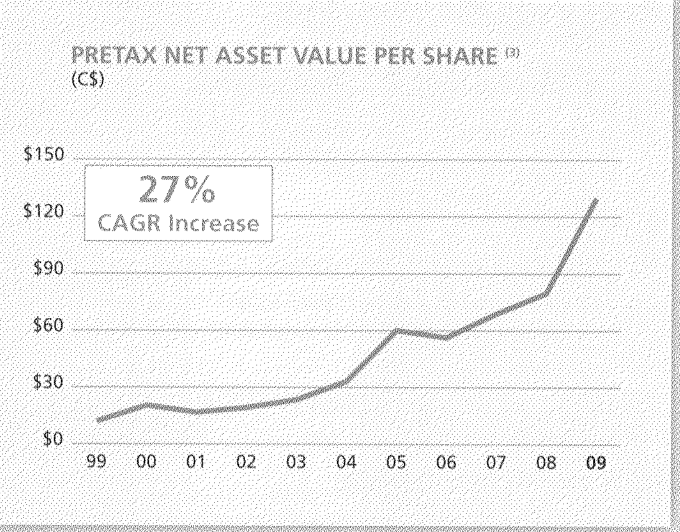
OUR METRICS

THE SUCCESS OF OUR CORPORATE BUSINESS STRATEGIES ARE MEASURED BY FOUR METRICS THAT DEMONSTRATE CONSISTENT PERFORMANCE.



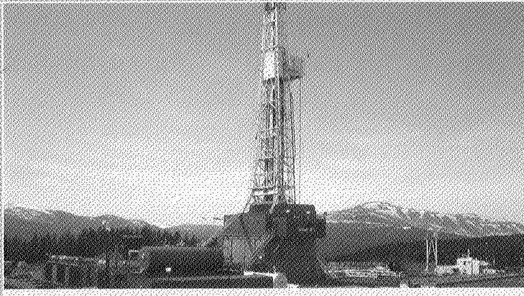






1) Based upon constant price and costs. Includes proved and probable reserves.
2) Cash flow from operations is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and repay debt. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").
3) Based upon 10% discounted, forecast price pre-tax proved and probable net present values as reported in the Company's Annual Information Form ("AIF") for reserves, with $250/acre added for core undeveloped land from 2005 to 2009, $75/acre for all years prior, less net debt. Excludes Horizon SCO reserves prior to 2009. Future development costs and associated material well abandonment costs have been applied against future net reserves.

OUR ASSETS



Deep Basin, Alberta

North America natural gas

Canadian Natural is the second largest producer of natural gas in Western Canada with average production of 1,287 mmcf/d in 2009. Our natural gas assets are strong, leveraged by a vast land base, well developed infrastructure and a deep, diversified inventory of drilling prospects. Given current economic realities of the natural gas business, our current focus is on continued optimization of operations and selective drilling of prospects to protect our land rights and set up future development. However, within our large inventory of unconventional plays we have development opportunities that can compete with crude oil projects. In 2010, we will commence development of a new shale natural gas play in Northeast British Columbia that will include a 50 mmcf/d expandable processing facility.

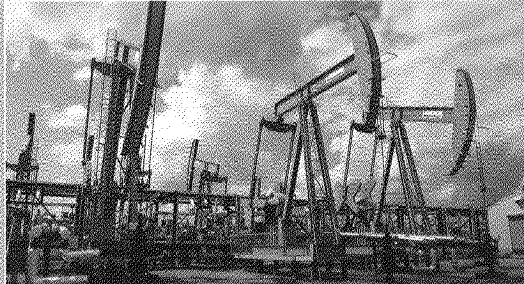
Elk Point, Alberta

North America crude oil and NGLs

Canadian Natural is one of the largest conventional producers of crude oil in Western Canada, producing 234,523 barrels per day of crude oil and NGLs in 2009. We hold a balanced portfolio of crude oil assets producing light, Pelican heavy, primary heavy and thermal heavy. We hold enormous potential within our land base well beyond today's identified drilling prospects.

Primary heavy crude oil

In 2009, approximately 500 primary heavy crude oil wells were drilled. In 2010, we target to drill over 600 wells, a record program for the Company. Our primary heavy crude oil assets, although shorter in life, provide quick payback and an exceptional return on investment. These assets provide an excellent balance to our longer term capital intensive projects, such as mining and in-situ oil sands.



Primrose, Alberta

Pelican Lake

Our world class pool, Pelican Lake, exemplifies the optimization of technology applied to an existing asset. What initially started as a primary horizontal drilling prospect, has now progressed into a very successful polymer flood. We anticipate that 80% of the field will be under polymer flood by the end of 2014, increasing both production and recoverable reserves.

Thermal crude oil

Our extensive thermal crude oil asset base will deliver continued growth over the next 20 years. The Company's long-term plan will add a new project or phase of approximately 30,000 to 60,000 barrels per day every two to three years. By 2020, we target to exceed 405,000 barrels per day of thermal production. The Kirby Project is the next phase of the plan. Engineering is currently underway and regulatory approval is expected in 2010. We target to sanction the project by late 2010.

OUR LAND BASE AND ASSETS

North America Crude Oil

Thermal

- Land base of 515,000 net acres;
- Large inventory of identified premium undeveloped assets will provide value added projects for the next decade;
- Current production capacity of approximately 120,000 barrels per day; and
- 33 billion barrels of estimated bitumen in place in the McMurray and Clearwater formations.

Pelican Lake

- World class crude oil pool with over 4 billion barrels of original oil in place ("OOIP") on Canadian Natural lands;
- Recoverable reserves and contingent resources of 560 million barrels through polymer flooding and primary production; and
- Plan to convert 80% of the field to polymer flood by the end of 2014, increasing production to 60,000 barrels per day.

Primary Heavy

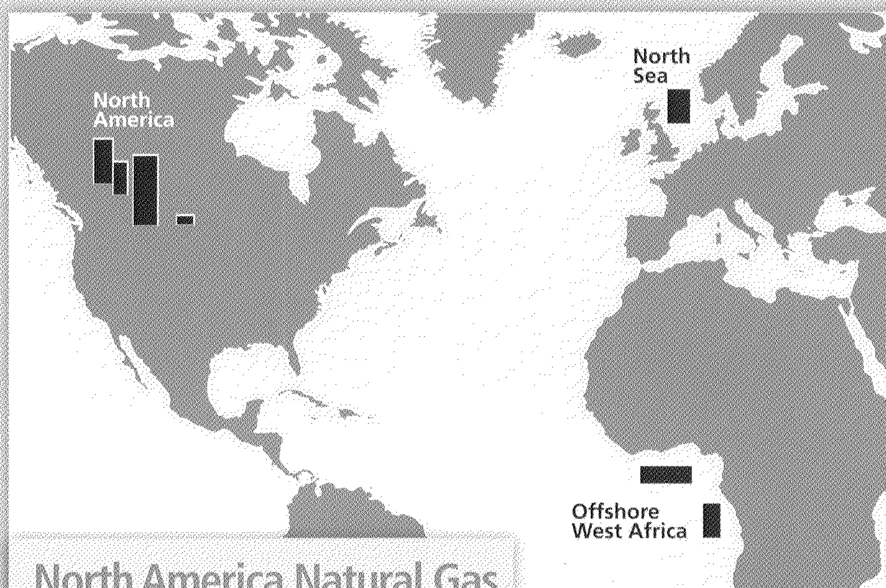
- 1.4 million net acres of developed and undeveloped land, and a dominant infrastructure position;
- Inventory of approximately 6,000 potential drilling locations;
- Record drilling in 2009 of approximately 500 wells with a target to drill over 600 wells in 2010; and
- Low capital and operating costs allow heavy crude oil assets to generate significant free cash flow through commodity price cycles.

Light

- Provides excellent balance to our portfolio;
- Ability to minimize operating costs through efficient operations; and
- Land base provides opportunities for reserves and production growth using enhanced oil recovery techniques.

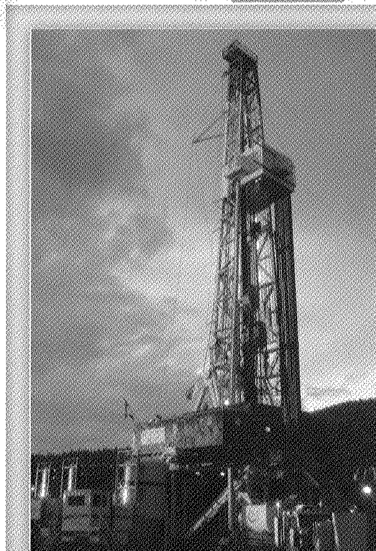
Canadian Natural's land base has grown significantly since inception. Today we have one of the largest conventional land bases in the Western Canadian Sedimentary Basin, with undeveloped acreage of 10.6 million net acres. The breadth and depth of our land base, well balanced assets and a well defined plan for development provide a large inventory of capital allocation choices.

Our dominant land base provides us years of inventory in primary heavy crude oil, thermal crude oil, light crude oil, Pelican Lake crude oil, and conventional and unconventional plays in natural gas. We continue to increase our inventory opportunities through land purchases and strategic acquisitions. Internationally, we will evaluate and capture value added light crude oil opportunities that leverage our strong team and technical skills.

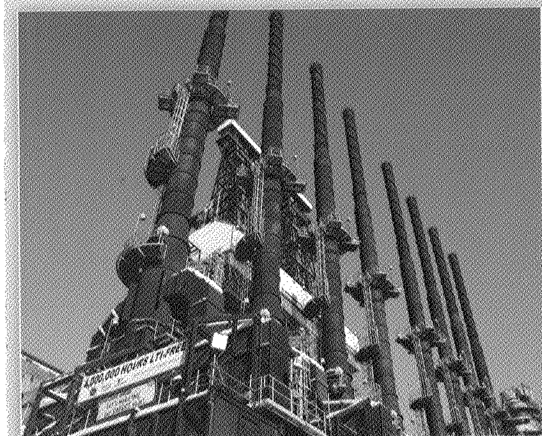


North America Natural Gas

- Largest land base holder in Western Canada with 14.6 million developed and undeveloped net acres which provides exposure to conventional, unconventional and deep exploration opportunities;
- Extensive infrastructure of over 21,000 miles of pipeline and a high level of operatorship facilitates low cost production;
- Large inventory of drilling prospects with more than 8,000 potential locations allows for high grade opportunities through commodity and cost cycles; and
- In 2010, unconventional development will focus on our large Montney position in Northeast British Columbia.



OUR SKILL SET



Horizon Oil Sands

- Resources of 16 billion barrels OOIP with best mining estimate recoverable OOIP of 6 billion barrels;
- Upgraded light, sweet crude oil helps balance our portfolio and reduces competition in the heavy crude oil market;
- No production declines normally associated with crude oil and natural gas activities with decades of estimated reserve life; and
- Future expansions target 500,000 barrels per day of production from our leases.

International

North Sea

- Significant potential with 5 billion barrels OOIP;
- Solid inventory of exploitation based value creation while delivering field life extension; and
- Provides substantial free cash flow to the Company.

Offshore West Africa

- Sizeable resource with 1.5 billion barrels OOIP;
- Operated with high working interest;
- Opportunity for exploitation; and
- Provides substantial free cash flow to the Company.

The Company has not only grown in production and asset base, but also in the strength of technical, operational, financial and managerial skills demonstrated by our team of excellent people.

Today we operate in complex basins across Western Canada, the North Sea and Offshore West Africa, all of which require diverse skills and expertise. The growth of the Company has resulted in a commensurate amount of knowledge in heavy crude oil, thermal in-situ, oil sands mining, offshore deep water, unconventional natural gas and enhanced oil recovery.

The crude oil and natural gas recovery technologies have changed dramatically in the last twenty years and Canadian Natural has been able to take advantage of these improvements by gaining the necessary technical skills to optimize resource recovery. Technology continues to evolve in all disciplines; however, it is our prudent application of technology that yields economic success and value creation for our shareholders.

Our expertise include:

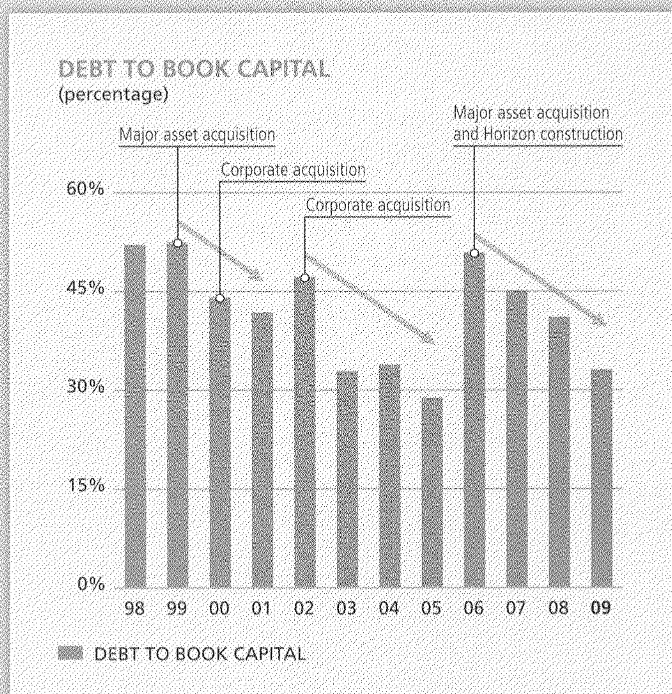
- More than 14 years of planning, developing and operating thermal in-situ projects incorporating both cyclic steam stimulation and steam assisted gravity drainage recovery processes;
- Extensive expertise in secondary recovery by operating more than 100 waterflood projects around the world;
- Testing tertiary recovery with CO_2 flooding in Southern Alberta and evaluating applications in other core areas;
- The largest polymer flood in North America and the second largest in the world;
- Commercial production of Coal Bed Methane in Central Alberta;
- Development of natural gas from shallow gas reservoirs in the plains of Alberta to the deep, structurally complex reservoirs in the foothills of Western Alberta and Northeast British Columbia;
- Development of new shale gas reservoirs in Northeast British Columbia and Western Alberta;
- Offshore expertise in Floating Production Storage Offtake vessel operations, deep water drilling and secondary recovery;
- More than 895,000 km of 2D seismic, 62,500 sq. km of 3D seismic, seabed logging, and LIDAR (Laser Detection and Ranging);
- Open pit mining and bitumen extraction processes;
- Primary and secondary upgrading expertise;
- Mega-project management skills; and
- Marketing and market development expertise.

OUR DEFINED PLAN

Canadian Natural operates its business according to overarching principles and maintains dedicated adherence to those principles. Our strategy is based on a low risk approach which has created significant shareholder value for over twenty years.

Our historical production growth is evidence of prudent capital discipline as we balance organic projects with acquired production. By maintaining stringent internal requirements for asset returns, we target the highest return projects possible. Our land base, people and skill set facilitates balance and exploitation opportunities, allowing us to focus on capital allocation to maximize returns.

In the future, the Company targets to reduce debt levels with our free cash flow as we build capacity for the next leg of growth. At the same time, we continue to look for organic and acquired growth opportunities, provided economic returns are sufficient. Canadian Natural is proud of its transparent strategy and strong growth profile.



Dedicated Return to Shareholders

The Company's ultimate goal is to create value for our shareholders and we do this by returning dollars on their investment. The Company continuously evaluates its performance to determine the most efficient way to ensure shareholders are rewarded for their commitment. The Company's share value has grown exponentially in the last decade and in 2010, we have declared an increase in the dividend for the tenth consecutive year, resulting in a compound average of 22% per annum since inception.

Capital Discipline

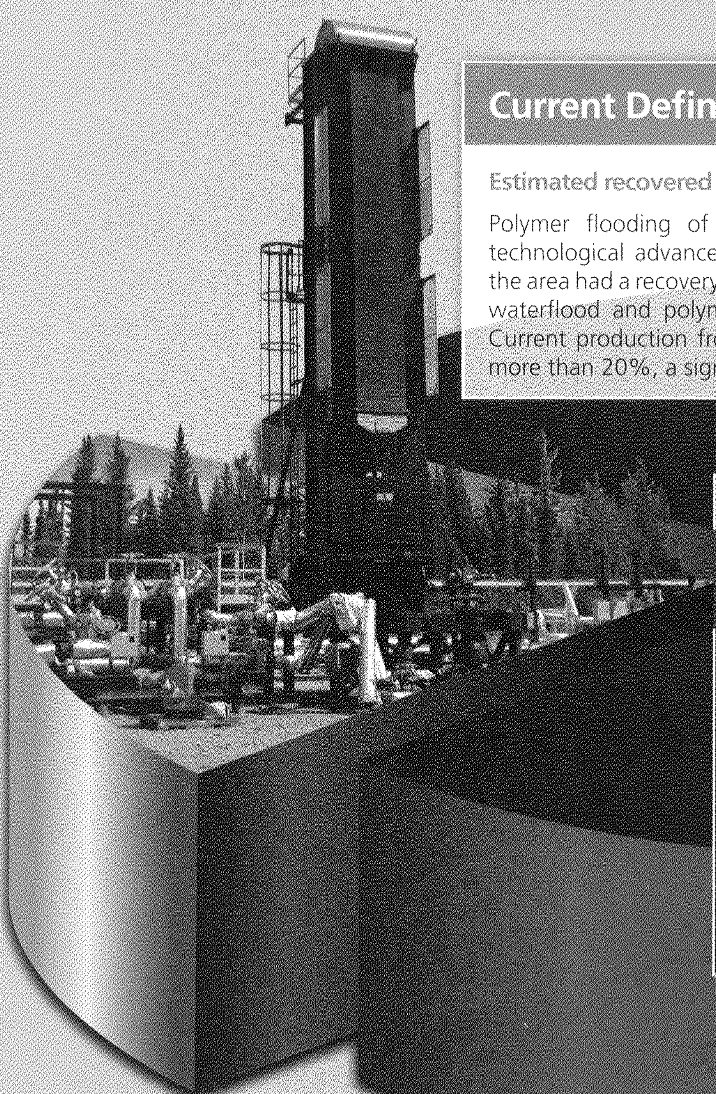
One of the main objectives of the Company is to maintain a strong balance sheet. We believe by doing so, we are always able to take advantage of opportunities that fit with our long-term plan. When we execute on these opportunities we immediately return focus to returning our balance sheet to a flexible position.

OUR FUTURE

We have the resources, we have a Defined Plan and we strive towards successful execution. So what does the future hold?

Today, using current technology, we are able to extract only a portion from the resource potential of our assets. Improvements in recovery techniques will add to the reserve life of our assets and significantly add value with relatively low initial investment. The industry is currently building upon existing technology to take advantage of resource recovery potential. In anticipation of possible breakthroughs, we continue to prepare the Company through planning and evaluation. This includes:

- Positioning the Company with land base and infrastructure to capture the upside of technological improvements;
- Utilizing technologies to unlock value in our current asset base by using thermal asset improvements;
- Identifying additional locations that would benefit from the use of polymer and locations where other injected solutions may create value;
- Evaluating the untapped resource potential of our unconventional natural gas plays;
- Identifying ways to improve recovery in all our areas and most specifically, in our conventional heavy crude oil where we typically leave more than 85% of the crude oil behind; and
- Continuously evaluating our environmental impact and determining ways to improve our processes. For example, utilization of CO_2 sequestration at Horizon Oil Sands allows for synergistic activities enabling limited use of energy, water and quantities of CO_2. The effects are lower operating costs and minimized environmental impact.



Current Defined Plan

Estimated recovered amount of resource potential using current technologies

Polymer flooding of our Pelican Lake asset demonstrates the importance of technological advances. Without application of enhanced oil recovery techniques, the area had a recovery rate of approximately 5%. Incremental improvements through waterflood and polymer flood have increased the amount of recovery possible. Current production from our Pelican Lake asset indicates that recovery may reach more than 20%, a significant increase considering 4 billion barrels OOIP.

Optionality/Technology Upside

Estimated unrecovered amount of resource potential expected to benefit from technological improvements

When considering the size of the crude oil and natural gas pools in Western Canada, the North Sea and Offshore West Africa, and the strategic land position we hold in these areas, the potential added value is considerable. Our thermal assets have 33 billion barrels of estimated bitumen in place and we currently estimate future recovery to reach 5.6 billion barrels or a 17% incremental recovery. We would expect to increase recovery further with future technology advances, which may significantly increase reserves.

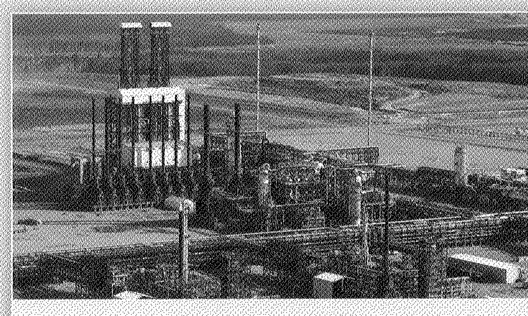
International

We maintain a very strategic approach with our International assets. The North Sea and Offshore West Africa ("OWA") both provide considerable free cash flow to the Company. In the North Sea and OWA, our assets provide low risk development opportunities such as infill drilling, step-out drilling, waterflood implementation and optimization, as well as operating cost optimization. Our portfolio also contains longer term exploration prospects in our Offshore South Africa land base.

Tiffany Platform, North Sea

Horizon Oil Sands

Our world class integrated oil sands mine and upgrading project achieved first synthetic crude oil (34° API) in 2009. The ramp up of production continues to progress as we encounter minor plant and equipment issues, and we anticipate reaching sustainable production by mid-2010. We continue to evaluate lessons learned from the first phase of the project and will leverage these findings in future phases. We remain committed to progressing with further expansions but we are patient and disciplined in our approach to ensure a cost effective and positive economic result.



North of Fort McMurray, Alberta

Marketing

Canadian Natural's marketing plan focuses on the delivery of our products through three distinct strategies. First, we blend our products to make them more attractive to the market; second, we commit production to pipeline infrastructure to ensure access to the market; and third, we obtain conversion capacity needed to upgrade and refine our products. In 2009, heavy oil differentials remained favorable due to refinery demand for heavy crude oil as crack spreads remained narrow. Proactive market development has resulted in higher values for heavy crude oil, allowing us to unlock the vast economic potential of our land base.

Infrastructure throughout Western Canada

OUR PERFORMANCE

		2009		2008		2007
FINANCIAL ($ millions, except per share data)						
Revenue, before royalties	**$**	**11,078**	$	16,173	$	12,543
Net earnings	**$**	**1,580**	$	4,985	$	2,608
Per common share – basic and diluted	**$**	**2.92**	$	9.22	$	4.84
Adjusted net earnings from operations (1)	**$**	**2,689**	$	3,492	$	2,406
Per common share – basic and diluted	**$**	**4.96**	$	6.46	$	4.46
Cash flow from operations (2)	**$**	**6,090**	$	6,969	$	6,198
Per common share – basic and diluted	**$**	**11.24**	$	12.89	$	11.49
Capital expenditures, net of dispositions	**$**	**2,997**	$	7,451	$	6,425
Long-term debt (3)	**$**	**9,658**	$	13,016	$	10,940
Shareholders' equity	**$**	**19,426**	$	18,374	$	13,321
OPERATING						
Daily production, before royalties						
Crude oil and NGLs (mbbl/d)						
North America - Conventional		**234**		244		247
North America - Oil Sands Mining and Upgrading		**50**		–		–
North Sea		**38**		45		56
Offshore West Africa		**33**		27		28
		355		316		331
Natural gas (mmcf/d)						
North America		**1,287**		1,472		1,643
North Sea		**10**		10		13
Offshore West Africa		**18**		13		12
		1,315		1,495		1,668
Barrels of oil equivalent (mboe/d)		**575**		565		609

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of 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.

	2009	2008	2007
Drilling activity (1)			
North America	**793**	984	1,060
North Sea	**1**	3	4
Offshore West Africa	**5**	3	4
	799	990	1,068
Core undeveloped landholdings (thousands of net acres)			
North America	**10,651**	11,603	12,160
North Sea	**150**	258	287
Offshore West Africa	**192**	192	192
	10,993	12,053	12,639
Company net proved reserves (2) (after royalties)			
Crude oil and NGLs (mmbbl)			
North America (3)	**2,664**	948	920
North Sea	**240**	256	310
Offshore West Africa	**123**	142	128
	3,027	1,346	1,358
Natural gas (bcf)			
North America	**3,027**	3,523	3,521
North Sea	**67**	67	81
Offshore West Africa	**85**	94	64
	3,179	3,684	3,666
Barrels of oil equivalent (mmboe)	**3,557**	1,960	1,969
Synthetic crude oil (3) (mmbbl)	**–**	1,946	1,761

(1) Excludes net stratigraphic test and service wells.

(2) December 31, 2009 reserve estimates are based upon 2009 12-month average reference price assumptions, as detailed below, and current costs. 12-month average price, as defined by U.S. Securities and Exchange Commission ("SEC"), is the unweighted average price of the first day of the month within the 12-month period prior to the end of the reporting period. Prior to December 31, 2009 year end prices and costs were used in reserve estimates.

(3) Prior to December 31, 2009, Horizon SCO reserves were reported separately in accordance to the SEC's Industry Guide 7. With SEC's Final Rule in effect January 1, 2010, this synthetic crude oil is now included in the Company's crude oil and natural gas reserve totals.

ALLAN P. MARKIN — Chairman

LETTER TO OUR SHAREHOLDERS

Canadian Natural continues to build a world class crude oil and natural gas company and create value for shareholders by delivering on key principles. We have made tremendous progress since our initial beginnings as a shallow natural gas producer in Western Canada and the journey is far from over as we have vast undeveloped assets to advance in the short-, mid- and long-term.

We believe that the assets that have been developed and acquired over the life of the Company provide balance and strength in all commodity cycles. The Company operates in both domestic and international basins and has successfully commenced production from our Horizon Oil Sands Project. Our Company provides a balanced portfolio, producing natural gas, light crude oil, heavy crude oil and synthetic crude oil. In all areas of our operations, significant resource potential remains for Canadian Natural and our shareholders.

Business Environment

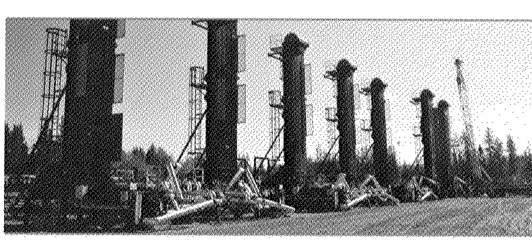
In 2009 we experienced a broad range of business environments. Early 2009 was anchored by a low commodity price environment and continued concern over economic conditions. In the second half of 2009, optimism began to grow, allowing crude oil prices to follow suit where they remained at relatively stable levels through to the end of the year. Heavy crude oil differentials were favorable through the year as refiners demanded heavy crude as crack spreads stayed narrow. Our proactive three-pronged marketing strategy to blend, increase conversion capacity and support pipeline capacity is paying off, and will continue to create value for our very significant heavy crude oil assets. The market for heavy crude oil has resulted in differentials to WTI near all-time lows.

Natural gas pricing remained challenged through 2009 as supply and demand fell out of balance and record storage levels in North America weighed on pricing. Economic conditions and the uncertainty for demand led to extreme volatility in natural gas pricing and prices in Alberta fell to decade lows. The outlook for natural gas prices remains uncertain as U.S. demand will need to grow to offset high storage levels and the strong growth capability from both U.S. and Canadian shale gas.

The Alberta royalty program changes announced in 2007 resulted in challenging economics for natural gas drilling within the province. Weak natural gas prices and re-allocation of capital by the industry reduced natural gas investment in 2009. This lack of drilling has led to softer drilling and service costs in Alberta possibly reaching a low point in 2009. Crude oil drilling and heavy crude oil netbacks are a robust return business for Canadian Natural and capital allocation in 2009 reflected these opportunities.

Business Approach

In the crude oil and natural gas industry, commodity price cycles are inherent in the business. To build a world class company not only must we withstand the downturns, but we must execute to come out even stronger. The Company focuses on the items we can control and ensures we maintain a low cost profile to weather commodity price storms. At the same time we take advantage of opportunities and look to grow the Company organically and through value added acquisitions. By looking at our execution and results over the last 20 years, it is evident our strategy has been effectively proven.



DEFINED PLAN: North America Crude Oil

1-2 years	3-5 years	Beyond
Primrose / Pelican / Primary Heavy	Potential for 5-7% CAGR	>20 years of development

N. MURRAY EDWARDS — Vice-Chairman

Our team is dedicated to efficient capital allocation that facilitates growth while maintaining financial strength. Our ability to generate internal cash flow allows us to be flexible in the way we do business. By having a diverse asset base, the Company is able to capitalize on the parts of the business that can provide acceptable returns even during difficult times. Our high working interest, large land base, and high operatorship allows us to focus on controlling the infrastructure in our areas and timing development, thereby delivering the highest returns.

2009 was a volatile and uncertain year as we came out of a very difficult economic downturn. Yet we were still able to pay down debt and deliver on our plan. We drilled a record number of primary heavy crude oil wells and proceeded with developments in our thermal heavy crude oil projects. Additionally, we continued development of enhanced oil recovery techniques at Pelican Lake, maintained our large undeveloped land base in Western Canada and achieved first oil at our Horizon Oil Sands.

North America Crude Oil

Our position in North America crude oil remains one of the strongest in the business. We are the largest producer of heavy crude oil in Western Canada, which has provided significant netbacks as heavy crude differentials remain narrow and we focus on maintaining low costs. We have extensive land holdings and significant development opportunities that will provide shareholder value over the long-term.

We manage our heavy crude oil assets in three main categories. In primary heavy crude oil, we concluded a record drilling program in 2009 with over 500 wells. These wells provide quick returns and are an excellent complement to some of our longer lead projects. In thermal heavy crude oil, we have a deep inventory of projects ahead of us. The 100% owned Primrose East expansion that was completed in 2008 continues to ramp up as our team works to mitigate an early resource containment issue. Work with the regulators carries on as expected and steaming is targeted to ramp up again in 2010. We will develop our thermal heavy crude oil resource in a stepwise and methodical manner to ensure we control the cost and deploy capital in the most efficient manner. We currently have plans capable of providing more than 285,000 barrels per day of incremental heavy crude oil production over the next several years. The next project, Kirby In-Situ Oil Sands, which will use steam assisted gravity drainage, is targeted to provide an additional 45,000 barrels per day of production capacity and have first steam injection in 2013. At Pelican Lake, we are converting the field to a polymer flood and expect to have flooded approximately 40% of the field by the end of 2010. The majority of the field is targeted to be converted over the next few years, enhancing recovery, increasing production and adding significant value.

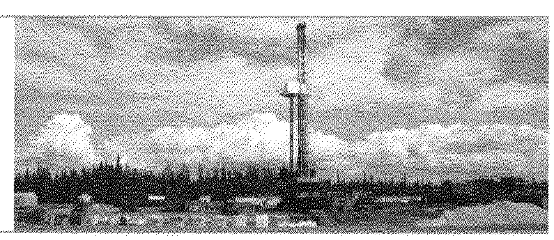
Light crude oil in Western Canada provides further balance to our overall asset base. We continue to optimize our field operations to increase recovery with waterfloods, and to evaluate and implement tertiary recovery to unlock value in our light oil properties. These enhanced recovery techniques include CO_2 floods in Southeast Saskatchewan and polymer floods in Southern Alberta. The strength of crude oil prices has also allowed our regional teams to target new light crude oil opportunities on traditional natural gas lands.

North America Natural Gas

Canadian Natural maintains one of the strongest natural gas positions in Western Canada. Being one of the largest producers and holding the largest undeveloped acreage position provides significant upside for this business. We continue to deploy capital as appropriate to these natural gas resources in order to control costs and set up future development. We have a balanced portfolio within our natural gas assets and will look to our unconventional areas such as the Montney shale gas, and areas of the Deep Basin to provide significant resource potential in the years to come. Our strategy will focus on the right timing to bring on these resources to ensure we maximize their value.

DEFINED PLAN: North America Natural Gas

1-2 years	3-5 years	Beyond
Optimize returns	Potential for 3-5% CAGR	>8,000 potential drilling locations



JOHN G. LANGILLE — Vice-Chairman

Natural gas economics cannot currently compete with our heavy crude oil projects, but we believe the time will come when natural gas can again compete economically. The focus in 2010 will be to mitigate expiries and drainage while drilling strategic wells for future development. We will leverage off our large infrastructure to help reduce costs. Our ability to be flexible in our capital allocation will allow us to unlock significant value from our large natural gas position when the opportunities present themselves.

International

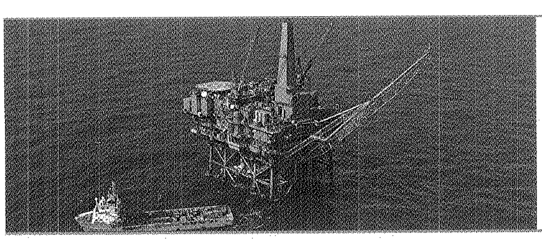
Our International assets also balance our portfolio as a source of light crude oil. Both the North Sea and Offshore West Africa core areas provide free cash flow, funding Company growth initiatives. We will take advantage of exploitation opportunities and recognize the potential for significant development prospects. We will leverage our North Sea learnings and experience to both Offshore Côte d'Ivoire and Gabon.

We operate the vast majority of our International assets and look for ways to maximize value. Cost reductions, high grading drilling inventory and identifying development drilling opportunities is key to value creation. In Baobab we have now completed the four re-drills of the failed wells from 2006, recovering approximately 11,000 barrels per day of production. At Espoir we continued with progress on upgrades to the Floating Production Storage and Offtake vessel to increase processing capacity. At Gabon we completed drilling on the first of four platforms on the Olowi Field. Although production from the first platform is below expectations, in 2010 we will drill the next scheduled platform and look at overall strategies for maximizing value from the project.

Horizon Oil Sands

2009 was a major milestone for Canadian Natural as first production at our world class mining project was achieved. The project was sanctioned in 2005 and since then, the team has worked diligently to complete construction of the plant targeting sustainable production of 110,000 barrels a day of 34° API crude oil. The team targets to complete the ramp up to full production by the middle of 2010. Through our disciplined and prudent approach to capital allocation, the Company has successfully built a legacy asset and retained 100% of the value for our shareholders with only nominal impact to the development plans for its other assets.

Potential expansions at Horizon are currently being re-profiled to optimize economics while reducing execution risk. The team will use 2010 to take lessons learned from Phase 1 and determine how to apply them to future phases. While many of our initiatives were successful, we recognize there are opportunities for improvement. The team will build on these lessons learned to help identify the best execution strategy going forward for future phases. Ultimately Horizon production is targeted at 232,000 to 250,000 barrels per day, but it is important we focus on the optimum execution to ensure we control costs and get the best value from the asset. Future expansions at Horizon must provide acceptable risk/reward parameters in order to proceed.



DEFINED PLAN: International

1-2 years	3-5 years	Beyond
Free cash flow	High return projects	Major growth area (acquisitions)

STEVE W. LAUT — President

Financial Strength

Management understands the importance of financial strength and promotes a low risk approach to our business. Not only does it ensure the Company survives during economic uncertainties, but it allows for flexibility in capital allocation. Our balance sheet is strong as the Company is generating significant free cash flow. Projects within the Company compete against each other for capital and therefore the highest return projects are allocated capital first. There are segments of our business where we could allocate more capital, but we will wait for the right time to maximize returns.

There are opportunities to mitigate some commodity price volatility through hedging and the Company will engage in hedging to protect a base cash flow. In years of high capital spending, the Company will accelerate the hedging program to underpin cash flows to ensure the projected capital requirements are met without exposing the Company to unnecessary risks. By employing this strategy, we are able to excel in all commodity and business conditions.

We have increased our quarterly dividend for the tenth consecutive year. The 2010 quarterly dividend on common shares increased by 43% to $0.15 per common share, payable April 1, 2010. This demonstrates the stability of Canadian Natural and our dedication to long-term shareholder returns.

Our Advantage

Our approach to our business is proven successful. Although an economic recovery appears to be underway, we remain cautious in our business approach. We will continue to utilize our large asset base to leverage cost saving opportunities. We will maintain our land base for future opportunities. We will continue to execute projects that provide the best returns and these opportunities are plentiful.

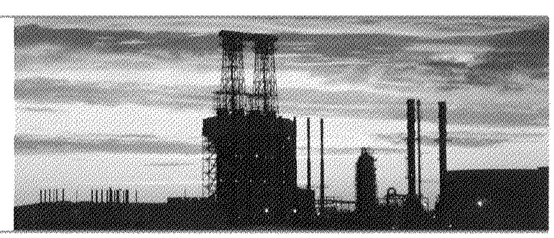
Our crude oil project inventory is extensive, as is our natural gas inventory, and they will be developed to provide significant value in the years to come. We continue to look forward to marketing strategies that will ensure we receive the best value for our heavy crude oil production. Our natural gas assets are strong and the opportunity to grow this part of our business will come and when it does we will be in a position to capture the value. Our International assets provide balance to our portfolio and our mining project at Horizon is now beginning to pay off. With all areas of our business providing free cash flow, the ability to grow our Company has never looked more promising.

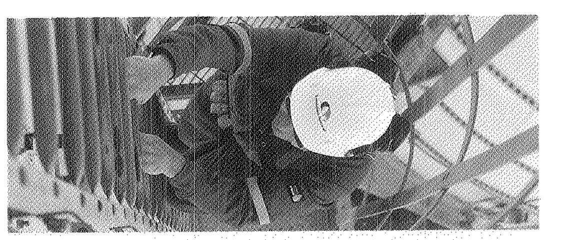
Our approach to our business is consistent and patient, just as it has been for over 20 years; this discipline is our advantage.

Allan P. Markin	N. Murray Edwards	John G. Langille	Steve W. Laut
CHAIRMAN	VICE-CHAIRMAN	VICE-CHAIRMAN	PRESIDENT

DEFINED PLAN: Horizon Oil Sands

1-2 years	3-5 years	Beyond
Stabilize production Re-profile expansions	Expansion to 232 - 250 mbbl/d	Expansion to 500 mbbl/d





OUR TEAM ADVANTAGE

Duncan Aamot, Lonnie Abadier, Walday Abeda, Peter Abercrombie, Darren Acheson, Belinda Adams, Michael Adams, Sean Adams, David Adamson, Debra Addinall, Adetokunbo Adebayo, Yemisi Adebayo, Richald Adzabe Ella, James Agate, Anurag Agnihotri, Gerardo Aguirre, Miguel Aguirre, Sarshar Ahmad, Pervez Ahmed, Salman Ahmed, Shakeel Ahmed, Dong Ai, Garrisen Ailsby, Jason Airlie, Kristy Aitken, Jeffrey Akeroyd, Sina Akinsanya, Mounir Al Halabi, Joseph Albano, Suhaib AlDhabbi, Bruce Alexander, Gregory Alexander, Joseph Alexander, Vincent Alexander, Walter Alexandru, Daniel Alfred, Elena Algazina, Mohieddin Alghazali, Arshad Ali, Rachel Aliazas, Catriona Allan, David Allan, John Allan, Geoff Allen, Jill Allen, John Allen, John Allen, Trent Allen, William Allerton, Devin Allibone, Karen Almadi, Jocelyn Alonso, Khaled Alsouqi, Arturo Alvarez, Diane Amalaman, Gregory Amalia, Joann Aman, Traore Amara, Clark Ambler, Jonah Amedu, Sharareh Ameripour, Donald Ames, Sylvia Anaka, Jan Andersen, Troy Andersen, Diane Anderson, Georgina Anderson, Jeremy Anderson, Kelvin Anderson, Leonard Anderson, Perri Anderson, Richard Anderson, Sarah Anderson, Steve Anderson, Peter Andrekson, Janet Andrew, Bob Andrews, Todd Andrews, Evan Angel, Carlo Angeles, Nathaelle Ango Mfene, Carolyn Angus, Shehzad Anjum, Stuart Annis, Greg Anstey, Helen Antle, Jamie Antle, Kathy Antonishyn, Shelley Antonuk, Brandon April, Richard April, Luc Arbour, John Arçan, Humberto Arias, Juan Arizaleta, James Arkley, Anthony Armstrong, Darryl Armstrong, Randall Armstrong, Rob Armstrong, Colin Arnold, Monique Arsenault, Bala Arunachalam, Arthur Ashley, Bonnie Ashley, Randy Aslin, Steven Aspden, Randy Asselin, Jacqueline Asso, Victoire Assohou-Ooattara, Francklin Assoko-Mve, Andrew Astalos, John Atkinson, Edwin Au, Gordon Au, Dominick Aubut, Jason Auch, Bernard Auger, Richard Augustyn, Carlos Aular, Reinaldo Aular, Ryan Austin, Maria F Avila, Carlos Aviles, Ward Ayles, Farooq Azam, Krishnaswamy Babu, Adrian Baciulica, Angela Bacon, Michael Baddeley, Vijay Bagde, Babak Baghban, Alex Bagnall, Mirka Baguela, Brian Bahlieda, Dave Baier, Janice Baik, Michael Baik, Dwayne Bailer, Rod Bailer, Alex Bailey, Brandon Bailey, Judy Bailey, Kimberley Bailey, Roysden Bailey, Leon Bakaas, Shane Baker, Sharon Baker, Thomas Balakas, Reginald Baldock, Charity Baldwin, Mark Baldwin, Robert Baldwin, Vaughn Baldwin, Irineo Balicanta, Joel Balkam, Darin Balkwill, Michael Ball, Gary Ballas, Ronnie Ballas, Sheldon Ballas, Brenda Balog, Corrie Balogh, Ladji Bamba, Mamadou Bamba, Mike Bamber, Neville Banak, Saiyed Banamia, Darwin Banash, Junet Banawa, Mark Bancroft, Bob Banks, Linda Banks, Bennett Bannis, Teresa Banny, Cirilino Bantaya, Inge Bantli, Marvin Bantugan, Garry Bardoel, Larry Bardoel, Pamala Bare, Dale Barge, Muhammad Bari, Ross Barker, Sharon Barker, Dennis Barnes, Michael Barnes, Tiziana Barnes, Beata Barnett, Javier Baroja, Deborah Barr, Sean Barr, Brenda Barron, Robert Barten, Carrie Barter, Blair Bartlett, Cynthia Bartlett, Eddie Bartlett, Catlin Bartman, Marty Bartman, Lloyd Basines, Michael Batac, Cheryl Bateman, Lisa Bateman, Selena Bath, Mark Batovanja, Brenda Battyanie, Jackie Bauer, Lydell Bauer, Ronnie Bauer, Raymond Bazan, Martin Beach, Andrew Beacon, Colin Beaman, Harold Beamish, Chad Beaton, Aura Beattie, Randall Beatty, Erica Beauchamp, Richard Beaudoin, Guy Beaulieu, Laurier Beaunoyer, Francis Beaver, Brent Beck, Chris Becker, Bryce Beckner, Gurpreet Bedi, Gregory Bednarchuk, Sheldan Beebe, Keith Begg, Loren Behrens, Anhar Belah, Darina Belanger, Guy Belanger, Kelly Belanger, Lesley Belcourt, David Belisle, Dustin Beliveau, Calvin Bell, Jon Bell, Nigel Bell, Stephen Bell, William Bell, Reg Bellanger, Janet Bembridge, Michael Bembridge, Ahmed Bendahmane, Khalida Bendahmane, Brad Bendick, Lene Benner, Chris Bennett, Murray Bennett, Brad Bensmiller, Shelly Bensmiller, Chad Benson, James Bentley, Linda Beresh, Debbie Berg, Jennifer Berg, William Berg, Jeffrey Bergeson, Becky Bergley, David Berlinguette, Henry Berlinguette, Daniel Bernardo, Lynn Bernhardt, Joanne Berrade, Murray Bertsch, Jeffrey Best, Jonathon Best, Rodney Best, Stewart Bettinson, Ashley Bexson, Rupal Bhatt, Pareshkumar Bhavsar, Del Bialowas, Marc Bickham, Jennifer Bidlake Schroeder, Corey Bieber, Daniel Bieber, Douglas Bielech, Derek Biener, Inge A Biener, Roger Binkley, Justin Binsfeld, Roger Bintz, Warren Birch, Robert Bischoff, Shane Bischoff, Christopher Bish, Kathy Bishop, Travis Bishop, Craig Bisschop, Darwin Bittner, Darcy Bjorge, Kevin Bjornstad, Adam Black, Chad Black, Chris Black, Craig Black, David Black, Leah Black, Paul Blackburn, Kenneth Blackhall, Kerri Blackmore, Daniel Blain, Deana Blais, David Blake, Evan Blake, Barton Blakney, Alvaro Blanco, William Blanco, Christopher Blatchly, Shawn Blaydes, Zoe Bleackley, Parrish Blizard, Rolland Blouin, Samantha Blouin, Gregory Blundon, Kyla Bly, Carlos Boadas Salazar, Henry Bocalan, Allan Boddy, Brad Bodnar, Dennis Boehmer, Kent Boerrichter, Kyle Boerrichter, Dean Boettcher, Darcy Boettger, Warren Bogelund, Marty Boggust, Tyler Bohach, Gordon Bohrson, Lauren Boida, Claude Boily, Evan Boire, Michael Bolianatz, Greg Bolin, Shawn Bond, Ariadna Bonilla, Tom Bonwick, Patricia Booklall, Martin Booth, Charlene Boraas, Barry Borbely, Adriana Borbon, Robert Borg, Mark Born, Michael Born, Jon Borstel, Blair Bosch, Keith Bottriell, Maurice Bouchard, Ronald Boucher, Suzanne Boudignon, Dylan Boudreau, Lance Boulet, Tyler Bouma, Rick Bourassa, Sheldon Bourassa, Delwood Bourke, Daryl Bourque, Christine Boussougou Mayagui, Daniel Boutin, Devrey Bowen, Jonathan Bowen, Robert Bowers, Slade Bowers, Bruce Bowles, Clinton Bowles, Nadine Bowles, Ernest Bown, Dale Boychuk, Doug Boyd, Patrick Boyd, Shirley Boyd, Charline Boyer, Lorraine Boyle, Richard Boyle, Neil Bozak, John Brabec, Dave Bracey, Bryan Bradley, Kenneth Bradley, Peggy Bradner, Janet Bradshaw, Marianne Brady, Mary Jane Brady, Linda Bragg, Jo-Ann Brake, Nicholas Brake, Tyler Branch, Dan Branescu, Brian Brant, David Brant, Myron Brataschuk, Colin Brausen, Luis Bravo, Neil Bray, Tess Bray, Gordon Brecht, Sharon Breitkreuz, Joseph Breland, Paul Breland, Stephen Brent, Barry Brenton, Lori Brenton, Ryan Brenton, Roxane Bretzlaff, Olaf Breukel, Lisa Brewer, Barry Brick, Butch Briggs, David Briggs, Denis Brisebois, Donald Britton, Lisa Brock, Shawn Brockhoff, Brian Broda, Kelly Broda, Dwayne Brodziak, John Brogly, Bill Bromling, Robert Bronson, Murray Brooker, Andrew Brooks, Debbie Brooks, Jeremy Brooks, Tanya Brooks, Kenneth Brosowsky, Eugene Brown, Jason Brown, Jennifer Brown, Jeremy Brown, Leroy Brown, Mary Brown, Steve Brown, Tracy Brown, Tyler Brown, Leo Browne, Robert Brownless, Christopher Bruce, Shelly Bruce, Fred Brugger, John Brule, Russell Brundige, Jason Bryant, Michelle Bryson, Sean Bryson, Gordon Buckshaw, Linda Buczkowski, Malcolm Budd, Robert Budzen, Raymon Bueckert, Darren Buffett, Wayne Bugiak, Ian Bulloch, Joe Bullock, Don Bumstead, Douglas Bumstead, Alan Bunyan, Clarence Bur, Trevor Burchenski, Jeffrey Burdett, David Burdziuk, Keith Bureau, Grant Burgess, Alastair Burke, David Burke, Lyle Burke, Angela Burnett, Ken Burnham, Robert Burns, Barry Burt, Shawn Burt, Gerald Burtch, Corinne Burton, Robert Busato, Lisa Bush, Colleen Bussey, David Bussey, Rosemary Bussi, Robert Butler, James Butt, Sharjeel Butt, Bob Butterworth, Ronald Butts, Leanne Butz, Peter Buxton, David Byrnes, Mike Byrtus, Irina Byvald, Moraima Caceres-Centeno, Krystal Cacka, Mark Cadman, James Cadrain, Ling Cai, Simon Cains, Winnie Calabio, Laura Calder, Leslie Calder, Byron Caldwell, Patrick Caldwell, Thomas Callaghan, Natalia Callejas, Patrick Callin, Richard E Calliou, Ian Cameron, Ryan Cameron, Lisa Campacci, Catherine Campbell, Clayton Campbell, David Campbell, Dean Campbell, Doug Campbell, Kyle Campbell, Michael Campbell, Niall Campbell, Andre Campeau, Wayne Campeau, Gregory Cane, Brad Canning, Elaine Cantlon, Kelly Cap, Richard Cap, James M Capjack, John Capstick, Barry Carabin, Kathleen Carbury, Fred Cardinal, Jason Cardinal, Lee Cardinal, Sharon Cardinal, Wayne Cardinal, Mark Carew, Justin Carey, Joey Carifelle, Rodger Carifelle, Ian Carleton, Stephanie Carlson, Wes Carlson, Dean Carnes, Albert Caron, Rochelle Caron, Diego Carrera, Janie Carrier, Michael Carrier, Wayne Carrigan, Kim Carrol, Ian Carroll, Shayne Carroll, Melissa Carson, Eduardo Cartaya, Eric Carter, Marilyn Carter, Michael Carter, Jessica Cartwright, Gary Case, Mary-Jo Case, Trevor Cassidy, Lance Casson, Mike Catley, Steve Caven, Richard Cawaling, Ciara Celis, Marco Celis, Ali Centeno, Samuel Cervantes, Andrew Chaisson, Sachi Chakravarty, Mark Chalmers, Samantha Chalmers, Erin Chamberlain, Kevin Champagne, Lise Champagne, Alan Chan, Anly Chan, Mel Chan, Ranee Chan, Sarah Chan, Tim Chan, Wayne Chandler, Alan Chaney, Christina Chang, Koh Chang, Claude Chaon, Deon Chappell, Harry Chappell, Darryl Charabin, Christopher Charbonneau, Colleen Chartrand, Roger Chartrand, Leon Chateauneuf, Siddique Chaudhry, Rajesh Chauhan, Gary Chaulk, Mark Chayko, Carl Cheeseman, Bo Chen, James Chen, Lulu Chen, Daniel Chenier, Mike Chernichen, Tyler Cherry, James Cheung, Kawaljeet Chhabra, Joel Chiasson, Gloria Chick, Al Chin, Melaine Chin, Sharon Chin, Trish Chipiuk, Thomas Chisholm, Randall Chodzicki, Raymond Chong, Brent Chopping, Brett Chorney, Carol Chorney, Curtis Chornohos, Alphonse Chretien, Ruth Christensen, Marianne Christianson, David Christie, Shawn Christie, Rob Christopher, Andy Chu, John Chuiko, Loy Chunpongtong, Heather Church, Sharon Church, Gerald Churchill, Roderick Churchill, Kadidiatou Cisse-Banny, Elaine Cissell, Michael Clapham, William Clapperton, Amanda Clark, Amanda Clark, Andrea M Clark, Janice Clark, Bradley Clarke, Ken Clarke, Martha Clarke, Sanja Clarke, Sanja Clarke, Shandon Clarke, Walter Clarkson, Greg Clegg, Joseph Clevenger, Denise Clifton, Karla Cluett, George Clutton, Brooke Coburn, Dale Coburn, John Coers, John Coggan, Brenda Coke, Leanne Colborne, Aubrey Colbourne, Robin Coles, Celibeth del Carmen Colina, Lorne Collard, Marc Collie, Grant Collier, Garth Collings, Curtis S Collins, Maria Collins, Robert Collins, Rod Collins, Anne Collison, Gordon Collison, Adam Collyer, Rebecca Conacher, John Condie, Mark Connellan, Spencer Constant, David Conybeare, Christopher Cook, Anna Cooke, Kenneth Cooke, Lori Cookson, Brian Coolen, Rob Coolen, Sean Coolen, Gary Coombe, Kent Cooper, Laura Cooper, David Coppard, Robert Coppard, Nicola Corbett, Mark Corell, Elaine Coreman, Clair Cormier, Rocky Cormier, Rosette Cormier, Veronica Cormier, Ronda Cornell, Grant Corner, Alessandro Corradi, David Corson, Jim Corson, Pierpaolo Corticelli, Harry Costello, John Cote, Sanga Coulibaly, Douglas Coull, Eric Coulombe, Kim Coulter, Jack Courchene, Robert Courchesne, Gerald Courtney, Kathryn Courtney, Dave A Cousins, David H Cousins, Mark Coutu, Peter Covell, Keith Cowger, Catherine Cowie, Gemma Cox, Randy Cox, Wade R Cox, Edward Cozicor, Nigel Crabb, Harry Crabtree, Richard Craft, Cody Craig, Layne Craig, Bruce Crain, Stephen Crake, Patrick Cramb, Calvin Crawford, Marina Crawford, Michael Crawford, Paul Crawford, Paul Crawford, Beverley Creed, Leanne Cressman, Roger Crichton, Kayla Critch, Wendy Crockford, Kevin Croft, Shane Croft, Stefan Croft-Bednarski, Gordon Crooks, Christopher Cross, Camille Croteau, Barbara Crowley, Linda Cruttenden, David Cruz, Anthony Csabay, Edgardo Cuello, Darrel Cunningham, Davis Cunningham, Tara Cunningham-Canfield, Arley Currie, David Currie, Elizabeth Currie, Brent Curtis, Troy Curzon, Dale S Cusack, Kenneth Cusack, Pat Cusack, Real Cusson, John Cutler, Chris Cyr, Suzanne Da Costa, Kevin d'Abadie, Victor Daboin, Andrew Dabrowski, Marivic Dacillo, Ganiyat Dada, Fakhri Dadashov, Gary Dahl, Hamid Dahmani, Mark Dailey, Eliane Dakaud, Brittany Dalby, Patrick Dale, Layne Dalgetty-Rouse, Germain Dallaire, Scott Dalrymple, Gary Daly, Stanley Dams, Everett Dana, Walter M Danchak, Trevor Daniels, Mike Danis, Gene Danyluk, Peter Danyluk, Daniel Daraban, Andrew Dareichuk, Corbin Dargatz, Eric Dargis, Mark Darling, Martin Darveau, Altaf Dasurkar, Bruce Davidson, Graham Davidson, Jeffery Davidson, Mike Davidson, Scott Davidson, Thomas Justin Davidson, Todd Davidson, Brian Davies, Charlee Davies, Lynne Davies, Frank Davis, Graham Davis, Greg Davis, Randall Davis, Robert Davis, Sarah Davis, Peter Davison, Leonard Dawe, David Day, Julia Day, Natasha Daya, David Daye, Douglas De Avila, Ryan De Bruyne, Meinrado de Chavez, Eric de Kock, Ryan De Leeuw, Benito De Lorenzo, Robbert de Ruiter, Albert De Sousa, Brian de Winter, David Dean, Harry Dean, Martha Dean, Trevor Debler, Ron Erick DeCastro, Derek Dechaine, James Dechaine, Raymond Dechaine, Roland Dechesne, Dave Defoort, Sheldon DeFord, Mervin J Degenstien, Barbara Deglow, Gerald Del Frari, Karin Delday, Mitchell Dell, Michael Delorme, Michael RJ DeLorme, Charlene DeMone, Whyman Dempster, Fred Denney, Judy Denney, Geoffrey Dennis, Susan Dennis, Kimberley Dennis-Wood, Shirley Denny, Christopher Denslow, Colin Derby, Jayme Derix, Shane Derlukewich, Greg Derouin, Semir Dervovic, Eugenie Dery, Ajit Desai, Nareshchandra Desai, Heidi Desaulniers, Miles Deschambeau, Darren Deschene, Raymond Desjarlais, Laurie A Devey, John devries, Fraser Dewar, Todd Dewhurst, Debbie Dewis, Karen Deyaegher, Maldip Dhaliwal, Pirmohammed Dhalwala, Jabeen Dharamsi, Kellie D'Hondt, Keith Diakiw, Karim Diallo, Sumara Diaz, Karen Dickason, Robert Dicken, Garry Dickie, Anthony Dicks, Blair Dickson, Cameron Dickson, Francis Dickson, Alexander Didenko, Sue Didyk, Brenda Diebel, David Diebel, Irene Dikau, Benjamin Dikit, Anne Dillon, Michael Dingley, Patricia Dingley, Ronald Dinkel, Hubert Dinn, Issiaka Diomande, Chris Dionne, Gayle Dionne, Michael Dirk, Tim Ditchburn, Al Dixon, Robin Dixon, Rod Dixon, Trent Dixon, Denise Dixson, Derrick Dobrowski, Leanne Dobson, Linnae Dobson, Edward Dochuk, Russell Dodd, Alistair Dodds, John Dodman, Erin Doepker, Kelly Doepker, Kim Doepker, Ritchie Doering, Robert Doering, James Doleman, Logan Dolen, Kathy Doll, Amy Dolomount, Brenda Dombrova, Kyle Donald, Scott Donaldson, Claire Dong, Veronica Dooling, Tim Dootka, Allen M Dorey, Tredou Dorgeles, Mark Dorocicz, Real Doucet, David Doucette, James Douglas, Martin Douglas, Dahl Dow, Angela Dowd, Jeff Dowd, Melissa Dowman, Phil Downes, Alecia Downton, Lisa Doyle, Darcy Draper, Kevin Draper, Kyle Draper, Todd Draper, Wayne Draper, Kenton Dreger, Brian Drew, Timothy Dreyer, Elaine Drolet, Christopher Drudge, Colleen Drury, Calvin Duane, Rafael Duarte, Sean Dubelt, Rosalind Ducey, Rick Ducharme, Peter Duda, Alan Duffy, Simon Dugdale, Douglas Duguid, Albert Duhaime, David Duke, Doug Duke, Cheryl Dumais, Laurent Dumoulin, Stella Dumoulin, Barry Duncan, Sean Duncan, Jason Duniece, Gavin Dunn, James Dunn, Krystal Dunn, Robert Dunn, Judy Dunsmuir, Kurt Dupuis, Lyle Dupuis, Michael Durnie, Harvey Dutchak, Robert Duval, Charles Dyer, Terry Dyer, Eugene A Dyjur, Linzi Dykes, Richard Dyson, Cindy Dzamon, Julina Eagleson, Gary Earl, Kevin Earle, Julie Easthope, Greg Ecker, James Edens, Malcolm Edirisinghe, John Edmunds, Josephine Edoukou, Gordon Edward, Dave Edwards, Michael Edwards, Sabrina Edwards, Cindy Egden, Phoebe Egden, Christopher Ehresman, Ingrid Eichelbaum, Brian Eitzen, Devin Ekdahl, Samuel Eleko, David Eley, Mahmoud Elgebali, Carole Eliuk, Anthony M Ell, Dean Ell, Diane Elliott, Michael Elliott, Robert Elliott, Trent Elliott, Karen Ellis, Shaun Ellis, Edwin Ellsworth, Matthew Elms, Maritess Eloursa Escanela, Heather Emery, Rommel Engler, Joanne English, Terry Erickson, Kresten Eriksen, Michael Ernst, Polina Ersh, Kelly Esquirol, Sarah Esson, Oscar Estrada, Andrew Etele, Samantha Etherington, Lee Evans, Randy Evans, Susan Eveleigh, Clayton Eves, Doug Eves, Laura Ewen, Kris Eyolfson, Leonard Fabes, Lawrence Facchina, Denis Fagnan, Heather Fahey, Richard Fairbairn, Andy Fankhauser, Greg Farrer, Randy Farrer, Travis Farrer, Barry Fast, Bryan Fast, Arthur Faucher, Chris Faucher, Everette Fauth, Karman Fayant, Tyson Feairs, Andrew Fearne, Ella Fedossova, Cody Fedun, Ira C Feland, Jeremie Feland, Warren Feland, Yves Felix-Tchicaya, Jason Feltham, Wallace Feltham, Enbo Feng, Kurt Fenrich, Logan Fentie, Randy Fenton, Colin Ference, Ken Ference, Lawrence Ference, Donald Ferguson, Helen Ferguson, Mark Ferguson, Neil Ferguson, Roy Ferguson, Scott Ferguson, Mario Feria-Estrada, Ana Camila Fernandez, Eduardo Fernandez, Sergio Fernandez-Trujillo, Ninfa Ferrer, Ron Fewer, Darren Fichter, Michelle Fielden, Jane Fielding, Walter Fielding, Chris Filgate, Michael Filipchuk, Tracy Fillmore, Neil A Findlay, Bob Finlayson, James Finlayson, Chad Finnebraaten, Kevin Finnerty, Timothy Finnigan, Tanya Fir, John Fisera, Calvin Fisher, David Fittkau, Sandra Fitzpatrick, Colleen Flamont, Ken Fleck, Doug Fleming, Rodney Flett, Trevor Flood, Reynaldo Flores, Edmond Foisy, Justin Foisy, Brent Foley, Yvonne Fong, Gregory Fontaine, Leo Fontaine, Robert Fontaine, Roger Fontaine, Lynn Foo, Randy Foran, Adele Forcade, Ryan Ford, David Foret, David Forfar, Curtis Formanek, Randy Formanek, Devon N Fornwald, Leslie Forrester, Alastair Forsyth, William Forsyth, Richard Forth, Danny Fortin, Donald Foster, Dwayne Fotty, Kevin Foulds, Scott Fouracres, James Fowler, Donna Frame, Fiona Frame, Roger France, Vicky France, Oscar Franchi, Ron Frank, Richard Franken, Allan Frankiw, Dru Franklin, Shelley Franssen, Gary Fraser, Leonard Fraser, Michael Fraser, Ken Frazer, Ted Frederickson, David French, Ernest French, Peter French, Roger Frere, Jared Frese, Kurt A Freyman, Brad Friesen, David Friesen, Kenneth Friesen, Monte Friesen, David Fritz, Andrei Frizorguer, Frank Frosini, Scott Froude, Xiao Wei Fu, Karen Fujimoto, Doug Fukushima, Jason Fung, Jim Fung, Sarina Fung-Yau, Ted Furuya, Donald Gabruck, Josephine Gaddi, Leonard Gadowski, Sharon Gaehring, Marcel Gagnon, Serge Gagnon, Serge R Gagnon, Jaylyne Galey, Ron Gall, Ryan Gallant, Fabio Gallardo, Michael Gallon, A William Galloway, Yoko Galvin, Andreas Gamp, Vovel Gapaz, Carlos Garcia, Carlos Garcia, Daina Gardiner, Doug Gardner, Lynette Gardner, Jon Gareau, Richard Gareau, Tim Gareau, Glen Garton, Linda Garvey, Stan Garwon, Carlos Garzon, Mark Gaspich, Victoria Gatchalian, Harold Gates, Janet Gatrell, Vanessa Gaudreau, Maurice Gauthier, Michelle Gauthier, Neil Gauthier, Klaus Gautschi, Rebecca Gayler, James Geddes, Michael Geddes, Cory Geier, David Geleta, Lesley Ann Gemmell, Glenn Genge, Neil Genge, Patricia Gentles, Devin George, William George, James Georget, Kimberley Gereluk, Jim Gergely, Matthew Gering, Grant Gerla, Jennifer Gerla, Michel Germain, Raymond Germain, Robert Germain, Colin Germaniuk, Karlene Gervais, Marc Gervais, Paul Gervais, Sheldon Getson, Glenn Getz, Nicole Getz, Stanley Getz, Ken Getzinger, Mohammad Reza Ghods-Esfahani, Essam Ghoubrial, Oliver Giammarioli, Douglas Gibson, Susan Giebel, Shaun Giefer, Todd Giesbrecht, Dwayne Giggs, Tamara 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Terry Potter, Randy Pottle, Craig Pottruff, Ryan Potts, Jesse Poulin, Dave Powell, Laurie Power, Lisa Power, Tiffany Power, Mitesh Prajapati, Dhrub Prasad, Jeffrey Pratt, Timothy Pratt, Mike Preece, Robert Prefontaine, Alanna Price, Rick Price, Robert Price, Dustin Pringle, Travis Prins, Melodi Pritchard, Doug Proll, Mangoueu Prosper, Richard Proulx, Kayla Prowse, Steve Pshyk, Yesid Edgar Puerto, Justyna Puhl, Nam Pui, Lance Pulak, Derek Pullem, Sachin Pupneja, Shantelle Purcell, Suniel Puri, Trent Pylypow, Kent Qin, Lu Qing, Munawar Quadri, Tony Quan, Duane Quigley, Ron Quiring, Samir Qureshi, Mandi Rabeau, Nathan Rabinovitch, Warren Raczynski, Nelda Radford, Barbara Rae, Gen Ragelyte, Subodh Chandra Raghavan, Jay Raher, Morteza Rahmanian, Priya Rai, Michael Rainey, Yina Raisbeck, Daniel Ralph, Vidas Ramachala, Cristina Ramirez, Ruth Ramonas, Lorraine Ramsay, Kerri Ramsbottom, Len Rancourt, Poonam Randhawa, James Rankin, Dorotea Ranola, Gregory Ransom, Jeremy Ransom, Tariq Rasheed, Chris Rasko, Shauna Rasmussen, Hadizata Rassi, Wade Ratcliffe, Soukseum Rathamone, Stojan Ratkovic, Murray Rattray, Andrew Rau, Carrie Rawlake, Derek Ray, Jason Rayner, Robert Rayner, Blair Read, Wilfred Read, Wayne Reashore, Teddy Reay, Deston Reber, Bernie Redlich, Adele Reed, Jon Reed, Keith Reed, Loreena Reed, Scott Reed, Tim Reed, Michael Rees, Duncan Rehm, Carmon Reich, Cameron Reid, Christopher Reid, Kerry Reid, Lilian Reid, Marty Reid, Sarah Reid-Bicknell, John Reiniger, Glenn A Reiter, Harvey Reithaug, Wendy Reitmeier, Daniel Rejman, David Rejman, Audrey Rempel, Long Ren, Shirley Renaud, George Renfrew, Alexander Rennie, Dustin Ressler, Jose Restrepo, Orville Reyes, Gregory Reynolds, James Reynolds, Pat Reynolds, Naseem Rhemtulla, Bruce Rice, Donna Rice, Jennifer Rice, Lisa Rich, Tammy Richard, Carolyn Richards, Charles Richards, Gerald Richards, Rob Richardson, Susan Richardson, Wesley Richardson, William Richardson, Lori Richmond, William Richmond, Jeff Riddell, Robert Riddell, Bonnie Ries, Darren Riley, Dominic Riley, Carl Ringdahl, Gordon Ringheim, Mike Rioux, Serge Rioux, Darren Risling, Lawrence Ritchat, Laura Ritchie, Ana Rivera, Carlos Rivera, Ismael Rivera, Sammie Rivet, Syedinamali Rizvi, Andrew Roach, Tracey Roasting, Jo-Anne Robak, Terrence Robbins, Christopher Roberts, Judie Roberts, Dale Robertson, Malcolm Robertson, Michael Robertson, Morag Robertson, Nancy Robertson, Stephen Robertson, Aaron Robinson, Amber Robinson, David Robinson, Gene Robinson, Julian Robinson, Scott Robson, Aaron Roche, Lennon Roche, Jesse Rockarts, Neal Roculan, Sheila Rodberg, Roger Rodermond, Ray Rodh, Paul Roett, Dean Rogal, Audrey Rogers, Martin Rogers, Murray Rogers, Lisbeth Rojas, Mercibeth Rojas- Bouchard, Paul Rokosh, Louis L Romanchuk, Dwayne Romanovich, Donny Romanyshyn, William Rombough, Eduardo Romeo, Joy Romero, Claude Rondeau, Darren Rondeau, Eric Rondeau, Jeffrey Rose, Andrew Ross, David Ross, Dennis Ross, Jason Ross, Robert Ross, Ron Ross, Graham Rosso, Worley Rosson, Barry Rosychuk, Cheryl Rosychuk, Rick Rosychuk, Roy Roth, Samuel Roth, Tom Roth, Katarina Rothe, Judy Rotzoll, David Rouleau, Gordon Rourke, Courtney Rousay, Richie Rovere, Natasha Rowden, Scott Rowein, Michael Rowland, Andre Roy, Beverly Roy, Dustin Roy, Zenita Ruda, Vivian Ruddy, Colleen Rudolph, Luis Ruesga, Marie- Louise Ruetz, Adam Ruff, Colleen Ruggles, Nigel Rusk, Ryan Rusnell, Denise Russell, Matthew Russett, Trevor Russo, Jeff Rutherford, John Rutherford, Peter Rutherford, Doug L Rutley, Justin Rutley, Mark Rutter, Hal Rutz, Rick Rybchinsky, Craig Ryder, Jeff Ryll, Ryan Saastad, Romulo Sabas, Mikael Sabo, Muhammad(Saqib) Saeed, Ludmila Safonova, Jochi Sahabandu, Ashok Saini, Poonam Saini, Joseph Sair, Darlene G Sakires, Rodrigo Sala, Alba Salazar, Carla Salazar, Diana Salazar, Shahid Saleem, Peter Salomon, Gord Salt, Geoffrey Samuel, Sirena Sanchez, David Sanderson, Michael Sanderson, Sandy Sandhar, Tom Sanelli, Eddy Sangroniz, Juan Pablo Santini, Theo Santos, Megan Santucci, Andrea SanVicente-Kraus, Sameer Saran, David Sargent, John C Sargent, Anita Sartori, Martin Sas, Greg Sauer, Lisa Saumier, Ashleigh Saunders, Chantelle Sauve, Jesse Savard, Luc Savoie, Michelle Savoie, Colin Savostianik, William Sawyers, Chris Sayer, Richard Sayer, Amber Sayers, Kimberley Scagliarini, Ryan Scammell, Brian Scarth, Robert Schaap, Trevor Schable, Bruce Schade, Judy Schafer, Brenda Schamehorn, Paul Schaub, Alan Schaufele, Lorne Schaufert, Perry Scheffelmaier, Keith Scheidt, Mike Schellenberg, Lance Schelske, Lou Scheper, Curtis Scherger, Sally Schick, Scott Schick, Dianne Schiewe, Brad Schiller, Mike Schiller, Andrew Schindel, Ronald Schlachter, Marcus Schlegel, Helen Schlenker, Casey Schmaltz, Jeannette Schmidt, Joseph Schmitz, Melissa Schmitz, Christopher Schneider, Darryl Schneider, David Schneider, Debbie Schneider, Jackie Schneider, Joseph Schneider, Paul Schneider, Blaine Schnell, Craig Schnepf, Aaron Schnick, Jack Schnieder, Ronald Schnieder, C Brian Schnurer, Rene Schoch, Stephen Schofield, Norm Schonhoffer, Sheldon Schroeder, Michael Schubert, Nathan Schuler, Stephen Schultheiss, Jaclyn Schultz, Randy Schultz, Kevin Schumacher, Derek Schutte, Lorraine Schwetz, Leslie Scory, Curtis Scott, Daniel Scott, Drew Scott, James Scott, John Scott, John Scott, Murray Scott, Ronalda Scott, Rodney Scoville, Ashley Scriba, Marc Scrimshaw, Ian Scully, Neil Scully, Gordon Seabrook, Christa Seaman, Geordie Seaton, Julia Seaton, Morley Seguin, Stephen Seguin, Linda Sehn, Paul Seipp, Mike Sell, Kenneth Selman, Leslie Semeniuk, Megan Semjanovs, Roland Senecal, Trevor Senger, Debbie Sereda, Derek Serfas, David Sergeant, Edward Serniak, Ligia Serrano, Cindy Severite, James Seward, Wanda Seward, Gianni Sgambaro, Maulesh Shah, Samir Shah, Sanjay Shah, Philip Shankowski, Raj Sharma, Brigitte Shaw, Lisette Shaw, Christopher Shears, David Sheaves, Wayne Sheaves, Ben Shenton, Iain Shepherd, Glenn Sheppard, Leah Sheppard, Robert Sheppard, Tim Sheppard, Ammul Shergill, Dean Shewchuk, Colin Shields, Nick Shier, Annette Shillam, Bill Shmoury, Bryden Shmyr, Brandon Short, Shawn Short, Dean Shortland, Leonard Shostak, Michael Shukalov, Robert Shumay, Lisa Shute, Evelyn Sibley, Indrajit Siddhanta, Melanie Siddon, Pritam Sidhu, Matthew Sidney, Wayne Sikorski, Beh Silue, Armindo Silva, Elvin Silva, Ismael Silva, Cam Simard, Kevin Simard, Vladan Simin, Francesca Simms, Doug Simoneau, Barbara Simpson, Brad Simpson, Gordon Simpson, Jilleen Simpson, Patrick Simpson, Elisha Sinclair, Garry Sinclair, Robert Sinclair, Jerret Singer, Sarbjeet Singh, Darcy Singleton, David Sirtonski, Richard Sisson, James Sjonnesen, Matt Skanderup, Kelly Skarra, Geoffrey Skinner, Michael Skinner, Michael Skipper, Max Skliarov, Grace Skoczek, Mary Skogland, Shirley Skulmoski, Martin Skulski, Nicolas Skulski, Michael Skyrpan, Michelle Slater, Michael Slavin, Edward Sleet, Delwin M Slemp, Darrell Sleno, Kevin Slotwinski, Jason Sloychuk, Doreen Smale, Samantha Small, Jocelyn Smid, Bill Smith, Blair Smith, Carl Smith, Catriona Smith, David LM Smith, Jason Smith, Maurice Smith, Michael Smith, Michael Smith, Nancy Smith, Robert Smith, Rory Smith, Ryan Smith, Sandi Smith, Sandra Smith, Scott Smith, Tim K Smith, Tina Smith, Todd Smith, Trevor Smith, Robert Smith-O'Brien, Allen Smyl, Richard Smyl, Brad Smylie, Tenielle Snell, Garry Snider, Kurt Snow, William Snow, Douglas Snyder, Jessica Solar, Jennifer Soley, Angelina Solis, Kathleen Soltys, Akshay Sonpal, Immanuelraj Soosaiprakasam, Gale Sopczak, Hans Sorensen, Curtis Sorochan, Daryl Soroko, Golam Sorwar, Dallas Spagrud, Paul Spavor, Edmund Spearman, Jason Spears, Robert Spears, Kevin W Spencer, Brent Spendiff, Darcy Spenst, David Spetz, Kelly Spiker, Tony Spitz, David Spooner, John Springer, Mike Sprinkle, Ellis Spurrell, Paul Spurvey, Arthur Squire, Lawson Squire, Murugan Srinivasan, Eric St Pierre, Robert St Amant, Gayle St Croix, Robert St Martin, Mario St Pierre, Barry StJean, Carrie Stacey, Jonathon Stacey, Ian Stacey-Salmon, Glen Stadnichuk, Stacey Stadnyk, Tyson Stafford, Kendall Stagg, Mark Stainthorpe, Karen Stairs, Ernesto Stamile, Randy Stamp, Nick Stanford, Laura Stang, Kristen Stark, Lezlie Stark, Christie Starnes, Scott Stauffer, Scott Stauth, Nicole Stebbings, Craig Steel, Richard Steele, Leanne Steeves, Gary Stefan, Silviu Stefan, Wayne Steffen, Carolyn Steinson, Allan Stella, Arnold Stella, Robert Stelten, Peter Stephen, Taryn Stephenson, Jane Stevens, Lyle Stevens, James Stevenson, Robert Stevenson, Robert B Stevenson, Carol Stewart, Charles Stewart, Cody Stewart, Dana Stewart, Douglas Stewart, Jordan Stewart, Lorie Stewart, Rory Stewart, Wendy Stewart, Rick Stieben, Stewart Stirling, Melissa Stockes, Mark Stockton, Shaun Stokes, Janet Storey, Didier Stout, Suzanne Strachan, Peter Strajt, Wade Strand, Robert Strang, Linda Strangway, Tanner Strangway, George Stratford, Brenda Stratichuk, Michael Street, William Stretch, Michael Stroh, Robyne Stroud, Robert Struski, Dwayne Strynadka, Linda Stuart, Peter Stuart, Paul Stuckey, SueAnn Stuckey, Russell Stuckless, Christopher Study, Mike Sturkenboom, David Sturrock, Ravi Subramaniam, Stephen Suche, Chris Suhan, Mark Sullivan, Victoria Sullivan, Effie Summers, Henan Sun, Tianxiang Sun, Daniel Sutherland, Rick Sutton, Scott Sverdahl, Amer Swadi, Christine Swan, Stephen Sweetapple, Nathan Swennumson, Stacey Swihun, Paul Swire, Edward Switzer, Ryan Switzer, Stacey Sydia, Don Sylvestre, Catherine Szmata, Derek Sztym, Szymon Szymczakowski, Jeffrey Ta, Vicky Ta, David Taggart, Arash Taghipour, Morgan Taheri, Patrick Taiani, Sanjay Talati, David Talbot, Miguel Tamayo, Mario Tandioy, Krystalle Tanner, Michael Tanouye, Cedric Tapley, Crisalida Tarache, Bill Tarkowski, Darcy Tarrant, Joanne Taubert, Nader Tavassoli, Raymond Taviner, Brian Taylor, Carla Taylor, Colin Taylor, Dawn Taylor, James Taylor, James R Taylor, Ken Taylor, Ken W Taylor, Paul Taylor, Todd Taylor, Joseph Taza, Chin Seng Teh, Jenny Tejada, Mariana Teleptean, Berhanu Temesgen, Tammy Temple, Derek Tempro, V Leighton Tenn, Kurt Tenney, Marilyn R Tenold, Gus Teske, Brock Tetz, Terence Tham, Richard Theberge, Mark Theriault, Marc Theroux, Bob Thibodeau, Richard Thibodeau, Chad Thiessen, Rinet (Maria) Thissen, Karen Thistleton, Laurie Thomas, Michael Thomas, Steven Thomas, Angela Thompson, Arthur Scott Thompson, Chris Thompson, Gerald Thompson, Herb Thompson, Ian Thompson, Kurtis Thompson, Mark Thompson, Peter Thomsen, Adele Thomson, Julie Thomson, Rory Thomson, Earl Thornton, Keith Thornton, Sharon Thuillier, Jason Thurlow, Margaret Thurmeier, Brian Tiffin, Michelle Tilford-Shaw, Daniel Tillapaugh, Joseph Tiller, Terry Tillotson, Colin Tiltman, David Timms, Simon Timothy, Neil Tindall, Bruce E Tipton, Dharmendra Tiwary, Ravindra Tiwary, Eric To, Carol Tobin, Ron Tochor, Joana Todica, Alfred Tokpa, Christopher Tomlinson, Dale R Tomlinson, David Tonner, Blair Torgerson, Lesley Torrance, Domenic Torriero, Michael Tosio, Derek Toullelan, David Tovey, Sabrina D Trafiak, Brittany Trask, Linda Trautman, Warren Trelinski, Edward Tremblay, Josie Tremblay, Maurice Tremblay, Catherine Trenouth, Jacklynn Trifaux, Brian E Trimble, Wade Trimble, Amy Trinh, Duc Trinh, Len Trotzuk, Rein Trotzuk, Rene Trudel, Ruaidhri Truter, Lisa Tsimaras, David Tuite, Sunny Tulan, Brent Tulloch, Neil Tulloch, Bruce Tumbach, Art Tupper, Terry Turgeon, Trent Turgeon, Richard Turnbull, Dave Turner, Ruth Turner, Stanley Turner, Brian Turpin, Danielle Turpin, Darren Turpin, Emily Turpin, Veronika Turska, Mark Tustian, Stephen Tuttle, Irene Tutto, Gordon Twin, Oleg Tyan, Angela Tyler, Wayne Tymchuk, Don Tyner, Peter Tyrer, Ekaide Ukat, Ivan Ulovich, Eric Ulrich, Gregory A Ulrich, Joselito Umali, Janis Underdahl, Nathan Underwood, Karl Unger, Earl Ungeran, Unnati Upadhyaya, Jackeline Urdaneta, Anand Vaidyanath, Allan Valentine, Gary L Valiquette, Darren Vallee, Louis Vallee, Michael Vallee, Anna Valmadrid, Dylan Van Brunt, Michelle van der Burgh, Liske van Heerden, Bryant Van Iderstine, Henk-Jan van Klinken, Salomon Van Rensburg, Charl Van Schoor, Christina Vander Pyl, Kevin Vandergaag, Yvette Vanderputt, Collin Vare, Michael Varga, Selena Varga, Ana Vasquez, Maria Vasquez de Placid, Nicolette Vaughan, Blaine Veitch, Gerrit Veldman, Brandon Velichka, Steve Venus, Jorge Vera, Sheila Verigin, Natalia Verkhoglad, Dan Verleyen, Nancy Tay Vetrici, Cesar Viana, Bonnie Vickery, Wilf Vielguth, Angu Vifansi, Christine Viljoen, Ronald Vinkle, Dean Vipond, Bill Virus, George Virus, Mark Virus, Santosh Vishwakarma, Tony Vitkunas, James W Vollman, Eric von Hertzberg, Luke Vondermuhll, Blake Von-Grat, Chrystal Voortman, Gary Wack, Richard Wack, Kyle Waddy, Gene Wafler, Valerie Wagar, Trevor Wagil, Joy Wagner, Juon Wah, Lee Wahl, Donald Wakaruk, Lance Wakefield, Michael Lane Wakefield, Kevin Wakulchyk, Jeff Walden, Dave Waldner, Darcy Waldo, David Walker, David Walker, Dean Wall, Erin Wallace, Greg Wallace, Kevin Wallace, Vince Wallwork, Patrick Walsh, Lorie Walter, Amanda Walters, Michelle Walton, John A Wandler, Ping Wang, Selina Wang, Wenyan Wang, Xiang Wang, Xing Zhu Wang, Blaise Wangler, Kevin Warcimaga, Danny Ward, Kathy Ward, Kirk Ward, Terry Ware, Wayne M J Warholik, Christopher Wark, Wanda Warman, Jason Warren, Rob Warren, Michael Warrick, Dalpreet Warring, Warren Waskowic, Paul T Wassell, James Waterfield, Frank Watkin, Julie Watkins, Devon Watson, Kaye Watson, Kenneth Watson, Debra Watt, Gordon Watt, Graham Watt, Heather Weaver, Alan Webb, Byron Webb, Dustin Webber, Keith Webster, Kim Wee, Eric Weening, Jeff Weibrecht, Derren Weimer, Lionel Weinrauch, Randy Weir, Brock Weisgerber, Bonnie Wells, Kelly Wells, Lisa Welsh, Guy Welwood, Mark S Wenner, Jeromy Wenzlawe, Dwayne Werle, Craig Werstiuk, Matthew Werstiuk, Ted Wesley, Darrin West, Michael Westad, Kris Westland, Troi Whalen, John Wham, Loyd Wheating, Ceri Wheaton, Joshua Wheaton, Andrew Wheeler, Charmaigne Whelan, Chris Whelan, Judd Whidden, David White, David White, Howard White, Jeffrey White, Ken White, Ralph White, Robert White, Terence White, David Whitehouse, Brian Whiting, Michael Whittingham, Heather Whynot, David Wiebe, Malcolm Wiebe, Debbie Wiens, Cameron Wietzel, Cheryl Wiggett, Zandra Wigglesworth, Steven Wight, Don Wijesingha, Bob Wilbern, Mason Wilcox, Brandon Wild, Darrell Wilde, John Wilding, Daryl Wiles, Troy Wilk, Clifton Wilkes, Melanie Wilkie, Derek Wilkinson, Pauline Will, Peter Will, Elmer Willard, Stanley Willette, Bill Williams, Brent Williams, Dustin Williams, Grant Williams, Greg Williams, Julian Williams, Sherri Williams, Wes Williams, Curtis Williamson, Kelvin Williamson, Malcolm Williamson, Monty Williamson, Brennon Willick, Jeff Willick, Robin Willis, Christian Willson, Curtis Wilson, Don Wilson, Ian Wilson, James Wilson, Jeff Wilson, Marty Wilson, Patrick Wilson, Tyler Wilson, Woodrow Wilson, Joan Wilton, Betty Winiarz, Daryl Winnicky, Jodie Winquist, Craig Winsor, Greg Winters, Garrett Wirachowsky, Jeff Wiseman, Morrison Wiseman, Paul Wiseman, Dale Wittman, Cameron Wlad, Kelly Woidak, Colin Woloshyn, C K Bill Wong, Jennifer Wong, Linda Wong, Lisa Wong, Maggie Wong, Pauline Wong, Julie Woo, Leonard Wood, Lynn Wood, Philip Wood, Roxanne Wood, Timothy Wood, Mark Woodfin, Travis Woods, Marilyn Woodske, Wayne Woodward, Robin Woolner, Sidney Wosnack, Raymond Wourms, Mark Woynarowich, Chris Wright, Richard Wright, Stephen Wright, Bin Wu, Diana Wu, Michael Wu, Jeff Wurzer, Christine Wutzke, Kelly Wutzke, Brent Wychopen, George Wyndham, Brent Wyness, Valerie Wyonzek, Qiang Xu, Kenneth Yakimowich, Canghu Yang, Zhen Lin Yang, Mike Yanota, Andrew Yaremko, Rick Yarmuch, James Yaroslawsky, Salman Yasin, Noah Yates, Basile Yeboue, Betty Yee, Davin Yee, Claire Yeoman, Justin Yeon, Jeffrey Yip, Kitty Yip, Mark Yobb, Ibrahim Yohanna, Amber Yoingco, Darrell York, Rachelle Yorke, Daryl Youck, Dale Young, Kevin Young, Lynn Young, Robert Young, Sylvia Young, William Young, Eugene Yu, Clement Yuen, Dustin Yuill, Jeff Yuill, William Yuill, Brian Yurchyshyn, Robin Zabek, Jesse Zacharuk, Tyler Zachoda, Cam Zackowski, David Zahara, Kent Zahara, Attila Zahorszky, Gabri Zambrano, Doug Zarowny, Kendall Zarowny, Chris Zeebregts, Lynn Zeidler, Tony Zeiser, Aleksandra Zelic, Diane Zeliznik, Devon Zell, Warren Zeller, Darcy Zelman, Denis Zentner, Kathy Zerr, Michelle Zerr, Rodney Zgierski, Jessica Zhang, Yingte Zhang, Litong Zhao, Susan Zheng, Zhenkun Zheng, Wanli Zhu, Brenda Ziegler, Megan Zilkey, Esther Zondervan, Aaron Zubot, Adriana Zuniga, Diana Zurabyan.

YEAR-END RESERVES

Determination of reserves

For the year ended December 31, 2009 the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, bitumen, natural gas, coal bed methane, and NGLs reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain provisions of National Instrument 51-101 – "Standards of Disclosure for 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. This exemption allows the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. On December 31, 2008, the SEC released its final rules for the modernization of oil and gas reporting ("Final Rule"). The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, and the directive to use 12-month average prices and current costs. These resulting changes are more in line with NI 51-101, however, there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, using 12-month average prices and current costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with Sproule and GLJ as to the Company's reserves.

Corporate net reserves

- Proved finding and on-stream costs, excluding Horizon SCO reserves, were $19.81 per barrel of oil equivalent with total reserve additions replacing 69% of production. On a three-year basis, proved finding and on-stream costs were $17.76 per barrel of oil equivalent. Using proved and probable reserves, finding and on-stream costs were $22.64 per barrel of oil equivalent and averaged $17.41 per barrel of oil equivalent over the past three years.

- Economic price revisions resulted in a reduction of 327 billion cubic feet of natural gas, 19 million barrels of crude oil and NGLs and 307 million barrels of SCO proved reserves. Absent these revisions and excluding Horizon SCO, proved finding and on-stream costs would have been reported at $12.28 per barrel of oil equivalent.

- Under revised SEC reporting guidelines, crude oil and natural gas reserves now include Horizon SCO reserves. The net proved SCO reserves, on a stand alone basis, have an associated cumulative Phase 1 finding and on-stream cost of $5.82 per barrel of oil equivalent.

North America net reserves

- Proved finding and on-stream costs for North American operations, excluding the impact of Horizon SCO reserves, were $12.78 per barrel of oil equivalent.

- Net proved reserve additions, excluding economic revisions due to prices, replaced 176% of 2009 production at a finding and on-stream cost of $6.45 per barrel of oil equivalent. Net proved and probable reserve additions, excluding economic revisions due to prices, replaced 213% of 2009 production at a finding and on-stream cost of $5.32 per barrel of oil equivalent.

International

- North Sea net proved reserves were 16 million barrels of oil equivalent less than 2008 as a result of technical revisions which were largely offset by positive price revisions.

- In Offshore West Africa net proved reserves decreased by 21 million barrels of oil equivalent to 137 million barrels of oil equivalent in 2009 due to production and negative price revisions.

RESERVES OF CRUDE OIL AND NATURAL GAS, NET OF ROYALTIES [1] [2]

	December 31, 2009			
	Proved Developed	**Proved Undeveloped**	**Proved Total**	**Proved and Probable**
Crude oil and NGLs (mmbbl)				
North America – Synthetic crude oil [3]	1,589	61	1,650	2,512
North America – Bitumen [4]	268	427	695	1,213
North America – Crude oil and NGLs	204	115	319	447
North Sea	94	146	240	387
Offshore West Africa	106	17	123	179
	2,261	**766**	**3,027**	**4,738**
Natural gas (bcf)				
North America	2,333	694	3,027	3,992
North Sea	45	22	67	94
Offshore West Africa	81	4	85	124
	2,459	**720**	**3,179**	**4,210**
Total reserves (mmboe)	**2,671**	**886**	**3,557**	**5,440**

FINDING AND ON-STREAM COSTS (excluding Horizon SCO reserves and capital)

	2009	2008	2007	**Three Year Total**
Net reserve replacement expenditures ($ millions)	**$ 2,377**	$ 3,475	$ 3,027	**$ 8,879**
Net reserve additions (mmboe) [5]				
Proved	**120**	168	212	**500**
Proved and probable	**105**	237	168	**510**
Finding and on-stream costs ($/boe) [6]				
Proved	**$ 19.81**	$ 20.68	$ 14.28	**$ 17.76**
Proved and probable	**$ 22.64**	$ 14.66	$ 18.02	**$ 17.41**

CRUDE OIL AND NGLs RESERVES RECONCILIATION, NET OF ROYALTIES (1)

	North America				International		Total
Net Proved Reserves (mmbbl) (2)	Synthetic Crude Oil (3)	Bitumen (4)	Crude Oil & NGLs	Total	North Sea	Offshore West Africa	
Reserves, December 31, 2008	–	690	258	948	256	142	1,346
Extensions and discoveries	–	24	6	30	–	–	30
Infill drilling	–	8	1	9	–	–	9
Improved recovery	–	–	74	74	–	–	74
SEC Reliable Technology (7)	–	7	–	7	–	–	7
SEC Rule Transition (8)	1,650	–	–	1,650	–	–	1,650
Purchases of reserves in place	–	–	1	1	–	–	1
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(64)	(8)	(72)	57	(4)	(19)
Revisions of prior estimates	–	79	11	90	(59)	(4)	27
Reserves, December 31, 2009	**1,650**	**695**	**319**	**2,664**	**240**	**123**	**3,027**

	North America				International		Total
Net Proved and Probable Reserves (mmbbl) (9)	Synthetic Crude Oil (3)	Bitumen (4)	Crude Oil & NGLs	Total	North Sea	Offshore West Africa	
Reserves, December 31, 2008	–	1,238	361	1,599	399	191	2,189
Extensions and discoveries	–	35	11	46	–	–	46
Infill drilling	–	12	2	14	–	–	14
Improved recovery	–	–	110	110	–	–	110
SEC Reliable Technology (7)	–	10	–	10	–	–	10
SEC Rule Transition (8)	2,512	–	–	2,512	–	–	2,512
Purchases of reserves in place	–	–	2	2	–	–	2
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(135)	(3)	(138)	13	(6)	(131)
Revisions of prior estimates	–	102	(12)	90	(11)	5	84
Reserves, December 31, 2009	**2,512**	**1,213**	**447**	**4,172**	**387**	**179**	**4,738**

(1) December 31, 2009 reserve estimates are based upon 2009 12-month average reference price assumptions, as detailed below, and current costs. 12-month average price, as defined by the SEC, is the unweighted average price of the first day of the month within the 12-month period prior to the end of the reporting period. Prior to December 31, 2009 year end prices and costs were used in the reserves estimates

Crude Oil and NGLs	**2009 12-month Average Price**	2008 Year-end Price	2007 Year-end Price
WTI @ Cushing Oklahoma (US$/bbl)	**$ 61.18**	$ 44.60	$ 96.00
WCS (C$/bbl)	**$ 58.49**	$ 33.07	$ n/a
North Sea Brent (US$/bbl)	**$ 59.91**	$ 41.76	$ 96.02
Company Average Price (C$/bbl)	**$ 59.39**	$ 34.51	$ 62.87

Natural Gas	**2009 12-month Average Price**	2008 Year-end Price	2007 Year-end Price
Henry Hub Louisiana (US$/mmbtu)	**$ 3.87**	$ 5.63	$ 6.80
Alberta AECO C (C$/mmbtu)	**$ 3.87**	$ 6.34	$ 6.52
British Columbia Huntingdon (C$/mmbtu)	**$ 3.92**	$ 7.48	$ 6.96
Company Average Price (C$/mcf)	**$ 4.02**	$ 6.51	$ 6.48

A foreign exchange rate of US$0.87/C$1.00 was used in the 2009 evaluation; US$0.82/C$1.00 was used in the 2008 evaluation; US$1.01/C$1.00 was used in the 2007 evaluation.

(2) Proved reserve estimates were evaluated in accordance with the new SEC requirements. The stated reserves have a reasonable certainty of being economically recovered using 12-month average prices and current costs held constant throughout the productive life of the properties.

(3) Prior to December 31, 2009, Horizon SCO reserves were reported separately in accordance to the SEC's Industry Guide 7. With SEC's Final Rule in effect January 1, 2010, this synthetic crude oil is now included in the Company's crude oil and natural gas reserve totals.

(4) Bitumen as defined by the SEC, under the Final Rule, "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. Prior to December 31, 2009, these reserves would have been classified within the Company's conventional crude oil and NGL totals.

NATURAL GAS RESERVES RECONCILIATION, NET OF ROYALTIES [1]

Net Proved Reserves (bcf) [2]	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Reserves, December 31, 2008	3,523	67	94	3,684
Extensions and discoveries	92	–	–	92
Infill drilling	7	–	–	7
Improved recovery	4	–	–	4
SEC Reliable Technology [7]	–	–	–	–
SEC Rule Transition [8]	–	–	–	–
Property purchases	15	–	–	15
Property disposals	(6)	–	–	(6)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(335)	12	(4)	(327)
Revisions of prior estimates	170	(8)	1	163
Reserves, December 31, 2009	**3,027**	**67**	**85**	**3,179**

Net Proved and Probable Reserves (bcf) [9]				
Reserves, December 31, 2008	4,619	94	131	4,844
Extensions and discoveries	111	–	–	111
Infill drilling	9	–	–	9
Improved recovery	4	–	–	4
SEC Reliable Technology [7]	–	–	–	–
SEC Rule Transition [8]	–	–	–	–
Property purchases	19	–	–	19
Property disposals	(7)	–	–	(7)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(429)	7	(5)	(427)
Revisions of prior estimates	109	(3)	4	110
Reserves, December 31, 2009	**3,992**	**94**	**124**	**4,210**

(5) Reserves additions are comprised of all categories of reserves changes, exclusive of production and Horizon SCO reserves.

(6) Reserves finding and on-stream costs are determined by dividing total cash capital expenditures for each year by net reserves additions for that year. It excludes costs associated with head office, abandonments, midstream and Horizon.

(7) SEC Reliable Technology accounts for reserves volumes added due to the reserves rule changes to allow booking of undeveloped reserves beyond one spacing unit with supporting geoscience and engineering data.

(8) SEC Rule Transition accounts for the inclusion of synthetic crude oil reserves volume additions as a result of oil sands mining being included as a crude oil and natural gas activity effective December 31, 2009. For continuity purposes, with respect to the transition from Industry Guide 7 into the SEC's Final Rule, the following Horizon SCO reserves table has been provided to illustrate the changes in the Horizon SCO reserves for the 2009 year.

Horizon SCO Reserves	**Net Proved** (mmbbl)	**Net Proved and Probable** (mmbbl)
Reserves, December 31, 2008	1,946	2,944
Production	(18)	(18)
Economic revisions due to prices	(307)	(434)
Revisions of prior estimates	29	20
Reserves, December 31, 2009	**1,650**	**2,512**

(9) The December 31, 2009 probable reserves have been evaluated in accordance to the new SEC requirements. Probable reserves are less certain to be recovered than proved but which when added with proved are as likely as not to be recovered. Prior to December 31, 2009, proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook and as mandated by NI 51-101.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, production volumes, royalties, operating costs, capital expenditures, and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") including the information in the "Outlook" section and the sensitivity analysis 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, Primrose East, Pelican Lake, Olowi Field (Offshore Gabon), and the Kirby Thermal Oil Sands Project 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 if 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 and 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 crude oil and natural gas 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 difficulties in mining, extracting or upgrading 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; 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, bitumen, natural gas and liquids 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 should circumstances or Management's estimates or opinions change.

SPECIAL NOTE REGARDING NON-GAAP FINANCIAL MEASURES

Management's Discussion and Analysis 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, cash production cost and net asset value. These financial measures are not defined by generally accepted accounting principles in Canada ("GAAP") 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 Canadian GAAP, 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 Canadian GAAP, in the "Financial Highlights" section of this MD&A. The derivation of cash production costs is 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

Management's Discussion and Analysis 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, 2009. The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). A reconciliation of Canadian GAAP to generally accepted accounting principles in the United States ("US GAAP") is included in note 17 to the consolidated financial statements. All dollar amounts are referenced in millions of Canadian dollars, except where otherwise noted. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the wellhead. Production volumes and per barrel statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of transportation and 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 2009 financial results compared to 2008 and 2007, unless otherwise indicated. In addition, this MD&A details the Company's capital program and outlook for 2010. Additional information relating to the Company, including its quarterly MD&A for the year and three months ended December 31, 2009, its Annual Information Form for the year ended December 31, 2009, and its audited consolidated financial statements for the year ended December 31, 2009 is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. This MD&A is dated March 3, 2010.

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	barrels
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	Heavy crude oil, generally more dense than 14° API
Brent	Dated Brent
C$	Canadian dollars
CAPEX	Capital expeditures
CBM	Coal Bed Methane
CICA	Canadian Institute of Chartered Accountants
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
Canadian GAAP	Generally accepted accounting principles in Canada
CSS	Cyclic steam stimulation
EOR	Enhanced oil recovery
E&P	Exploration and Production
FPSO	Floating Production, Storage and Offtake vessel
GHG	Greenhouse gas
GJ	gigajoules
GJ/d	gigajoules per day
Heavy Differential	Heavy crude oil differential from WTI
Horizon	Horizon Oil Sands
LIBOR	London Interbank Offered Rate
LNG	Liquid 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/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
OOIP	Discovered original oil in place
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
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

OBJECTIVE 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. 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 natural gas, light/medium crude oil and NGLs, Pelican Lake crude oil [2], primary heavy crude oil and thermal heavy crude oil and SCO;
- Balance among near-, mid- and long-term projects;
- Balance among acquisitions, exploitation and exploration; and
- Balance between sources and terms of debt financing and maintenance of a strong balance sheet.

(1) Discounted value of crude oil and natural gas reserves plus value of undeveloped land, less net debt.
(2) Pelican Lake crude oil is 14–17° 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 a 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.

Operational discipline and cost control are fundamental to the Company. By consistently controlling costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Cost control is attained by developing area knowledge, by dominating core areas 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 all of its growth projects. Additionally, the Company's risk management hedge program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures 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 regions.

Highlights for the year ended December 31, 2009 include the following:

- Achieved net earnings of $1.6 billion, adjusted net earnings from operations of $2.7 billion, and cash flow from operations of $6.1 billion;
- Completed the construction of Phase 1 of Horizon and commenced operations;
- Achieved annual crude oil and natural gas production guidance;
- Achieved first crude oil production from Platform C in the Olowi Field in Offshore Gabon;
- Reduced long-term debt by $3.4 billion to $9.7 billion in 2009 from $13.0 billion in 2008; and
- Increased annual dividend payout to $0.42 from $0.40, our 10th consecutive year of dividend increases.

NET EARNINGS AND CASH FLOW FROM OPERATIONS

Financial Highlights

($ millions, except per common share amounts)	2009	2008	2007
Revenue, before royalties	$ 11,078	$ 16,173	$ 12,543
Net earnings	$ 1,580	$ 4,985	$ 2,608
Per common share – basic and diluted	$ 2.92	$ 9.22	$ 4.84
Adjusted net earnings from operations (1)	$ 2,689	$ 3,492	$ 2,406
Per common share – basic and diluted	$ 4.96	$ 6.46	$ 4.46
Cash flow from operations (2)	$ 6,090	$ 6,969	$ 6,198
Per common share – basic and diluted	$ 11.24	$ 12.89	$ 11.49
Dividends declared per common share	$ 0.42	$ 0.40	$ 0.34
Total assets	$ 41,024	$ 42,650	$ 36,114
Total long-term liabilities	$ 19,193	$ 20,856	$ 19,230
Capital expenditures, net of dispositions	$ 2,997	$ 7,451	$ 6,425

(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" presented below lists 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" presented below lists the effects of 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.

Adjusted Net Earnings from Operations

($ millions)	2009	2008	2007
Net earnings as reported	$ 1,580	$ 4,985	$ 2,608
Stock-based compensation expense (recovery), net of tax (a)	261	(38)	134
Unrealized risk management loss (gain), net of tax (b)	1,437	(2,112)	977
Unrealized foreign exchange (gain) loss, net of tax (c)	(570)	698	(449)
Effect of statutory tax rate and other legislative changes on future income tax liabilities (d)	(19)	(41)	(864)
Adjusted net earnings from operations	$ 2,689	$ 3,492	$ 2,406

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

(b) Derivative financial instruments are recorded at fair value on the balance sheet, with changes in 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.

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

(d) All substantively enacted or enacted adjustments in applicable income tax rates and other legislative changes are applied to underlying assets and liabilities on the Company's consolidated balance sheet in determining future 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 or enacted. Income tax rate changes during 2009 resulted in a reduction of future income tax liabilities of approximately $19 million in North America. Income tax rate changes during 2008 resulted in a reduction of future income tax liabilities of approximately $19 million in North America and $22 million in Côte d'Ivoire, Offshore West Africa. Income tax rate and other legislative changes during 2007 resulted in a reduction of future income tax liabilities of approximately $864 million in North America.

Cash Flow from Operations

($ millions)	2009	2008	2007
Net earnings	$ 1,580	$ 4,985	$ 2,608
Non-cash items:			
Depletion, depreciation and amortization	2,819	2,683	2,863
Asset retirement obligation accretion	90	71	70
Stock-based compensation expense (recovery)	355	(52)	193
Unrealized risk management loss (gain)	1,991	(3,090)	1,400
Unrealized foreign exchange (gain) loss	(661)	832	(524)
Deferred petroleum revenue tax expense (recovery)	15	(67)	44
Future income tax (recovery) expense	(99)	1,607	(456)
Cash flow from operations	$ 6,090	$ 6,969	$ 6,198

For 2009, the Company reported net earnings of $1,580 million compared to net earnings of $4,985 million for 2008 (2007 – $2,608 million). The 2009 operating results of the Company were significantly impacted by lower benchmark crude oil and natural gas pricing, partially offset by the impact of the commencement of production from Horizon. Net earnings for the year ended December 31, 2009 included net unrealized after-tax expenses of $1,109 million related to the effects of risk management activities, fluctuations in foreign exchange rates, stock-based compensation, and the impact of statutory tax rate and other legislative changes on future income tax liabilities (2008 – $1,493 million after-tax income; 2007 – $202 million after-tax income). Excluding these items, adjusted net earnings from operations for the year ended December 31, 2009 decreased to $2,689 million from $3,492 million for 2008 (2007 – $2,406 million) primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expenses, higher depletion, depreciation and amortization expense, including the impact of a ceiling test impairment in Gabon, Offshore West Africa, higher accretion expense, higher interest expense, and the impact of realized foreign exchange losses, partially offset by the impact of higher crude oil sales volumes, lower royalty expense, realized risk management activities and the weaker Canadian dollar relative to the US dollar during 2009.

The impacts of unrealized risk management activities, stock-based compensation and changes 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 the year ended December 31, 2009 decreased to $6,090 million ($11.24 per common share) from $6,969 million ($12.89 per common share) for 2008 (2007 – $6,198 million; $11.49 per common share). The decrease was primarily due to the impact of lower realized pricing, lower natural gas sales volumes, higher production expense, higher interest expense and the impact of realized foreign exchange losses, partially offset by the impact of higher crude oil sales volumes, lower royalty expense, lower current income tax and PRT and the impact of realized risk management gains and the weaker Canadian dollar relative to the US dollar during 2009.

The Company's 2009 average sales price per bbl of conventional crude oil and NGLs decreased 30% to average $57.68 per bbl from $82.41 per bbl in 2008 (2007 – $55.45 per bbl). The Company's average natural gas price decreased 46% to average $4.53 per mcf from $8.39 per mcf for 2008 (2007 – $6.85 per mcf).

Total production of crude oil and NGLs before royalties increased 13% to 355,463 bbl/d from 315,667 bbl/d for 2008 (2007 – 331,232 bbl/d). The increase in crude oil and NGLs production was primarily due to new production from Horizon and the Olowi Field in Offshore Gabon, partially offset by the impact of planned maintenance shutdowns in the North Sea, and in North America due to the cyclic nature of the Company's thermal production and shut in of Primrose East for part of the year.

Total natural gas production before royalties decreased 12% to average 1,315 mmcf/d from 1,495 mmcf/d for 2008 (2007 – 1,668 mmcf/d). The decrease in natural gas production primarily reflected natural production declines and the Company's strategic reduction in natural gas drilling activity in North America.

Total crude oil and NGLs and natural gas production volumes before royalties increased 2% to average 574,730 boe/d from 564,845 boe/d for 2008 (2007 – 609,206 boe/d). Total production for 2009 was within the Company's previously issued revised guidance.

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) 2009	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties	$ 11,078	$ 3,319	$ 2,823	$ 2,750	$ 2,186
Net earnings	$ 1,580	$ 455	$ 658	$ 162	$ 305
Net earnings per common share – basic and diluted	$ 2.92	$ 0.85	$ 1.21	$ 0.30	$ 0.56
2008	Total	Dec 31	Sep 30	Jun 30	Mar 31
Revenue, before royalties	$ 16,173	$ 2,511	$ 4,583	$ 5,112	$ 3,967
Net earnings (loss)	$ 4,985	$ 1,770	$ 2,835	$ (347)	$ 727
Net earnings (loss) per common share – basic and diluted	$ 9.22	$ 3.27	$ 5.25	$ (0.65)	$ 1.35

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

- Crude oil pricing – The impact of fluctuating demand, geopolitical uncertainties on worldwide benchmark pricing, and the fluctuations in the Heavy Crude Oil Differential from WTI ("Heavy Differential") in North America.
- Natural gas pricing – The impact of seasonal fluctuations in both the demand for natural gas and inventory storage levels, and the impact of increased shale gas production in the US, as well as fluctuations in imports of liquefied natural gas into the US.
- Crude oil and NGLs sales volumes – Fluctuations in production from the Company's Primrose thermal projects, the results from the Pelican Lake water and polymer flood projects, and the commencement of operations at Horizon. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore West Africa and the impact of the shut in, and subsequent restoration of some of the production in the Baobab Field.
- Natural gas sales volumes – Production declines due to the Company's strategic decision to reduce natural gas drilling activity in North America and the allocation of capital to higher return crude oil projects, as well as natural decline rates.
- Production expense – Fluctuations primarily due to the impact of the demand for services, industry-wide inflationary cost pressures experienced in prior quarters, fluctuations in product mix, the impact of seasonal costs that are dependent on weather, and the commencement of operations at Horizon and the Olowi Field in Offshore Gabon.
- Depletion, depreciation and amortization – Fluctuations due to changes in sales volumes, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, the commencement of operations at Horizon and the Olowi Field in Offshore Gabon, and the impact of a ceiling test impairment at the Olowi Field at December 31, 2009.

- Stock-based compensation – Fluctuations due to the mark-to-market movements of the Company's stock-based compensation liability. Stock-based compensation expense (recovery) reflected fluctuations in the Company's share price.
- Risk management – Fluctuations due to the recognition of realized and unrealized gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- Foreign exchange rates – Fluctuations in the Canadian dollar relative to the US dollar impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominately on US dollar denominated benchmarks. Similarly, unrealized foreign exchange gains and losses were recorded with respect to US dollar denominated debt and the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars, partially offset by the impact of cross currency swap hedges.
- Income tax expense (recovery) – Fluctuations in income tax expense (recovery) include statutory tax rate and other legislative changes substantively enacted or enacted in the various periods.

BUSINESS ENVIRONMENT

(Yearly average)		**2009**		2008		2007
WTI benchmark price (US$/bbl)	**$**	**61.93**	$	99.65	$	72.40
Dated Brent benchmark price (US$/bbl)	**$**	**61.61**	$	96.99	$	72.59
WCS blend differential from WTI (US$/bbl) (1)	**$**	**9.64**	$	20.03	$	23.25
WCS blend differential from WTI (%) (1)		**16%**		20%		32%
SCO price (US$/bbl)	**$**	**61.51**	$	102.48	$	70.11
Condensate benchmark price (US$/bbl)	**$**	**60.60**	$	100.10	$	72.88
NYMEX benchmark price (US$/mmbtu)	**$**	**4.03**	$	8.95	$	6.92
AECO benchmark price (C$/GJ)	**$**	**3.91**	$	7.71	$	6.26
US / Canadian dollar average exchange rate	**$**	**0.8760**	$	0.9381	$	0.9304
US / Canadian dollar year end exchange rate	**$**	**0.9555**	$	0.8166	$	1.0120

(1) Beginning in 2008, the Company has quantified the Heavy Differential using the WCS blend as the heavy crude oil marker. Prior period amounts have been reclassified.

Commodity Prices

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 price is also highly sensitive to fluctuations in foreign exchange rates. The average value of the Canadian dollar in relation to the US dollar fluctuated significantly throughout 2009, with a high of approximately $0.97 in December 2009 and a low of approximately $0.77 in March 2009.

The overall decrease in WTI pricing in 2009 reflected a decrease in demand as a result of worldwide financial and economic events during the year, and ongoing geopolitical uncertainty resulting in increased market volatility, partially offset by strong Asian demand in the second half of the year. For 2009, WTI averaged US$61.93 per bbl, a decrease of 38% compared to US$99.65 per bbl for 2008 (2007 – US$72.40 per bbl).

Brent averaged US$61.61 per bbl for 2009, a decrease of 36% compared to US$96.99 per bbl for 2008 (2007 – US$72.59 per bbl). Crude oil sales contracts for the North Sea and Offshore West Africa are typically based on Brent pricing, which is more reflective of international markets and the overall supply and demand balance.

The Heavy Differential averaged 16% of WTI for 2009 compared to 20% for 2008 (2007 – 32%), reflecting relatively weak refinery margins.

The Company anticipates continued volatility in the crude oil pricing benchmarks due to the unpredictable nature of supply and demand factors, geopolitical events and the timing and extent of recovery of the global economy. The Heavy Differential is expected to continue to reflect seasonal demand fluctuations and refinery margins.

NYMEX natural gas prices averaged US$4.03 per mmbtu for 2009, a decrease of 55% from US$8.95 per mmbtu for 2008 (2007 – US$6.92 per mmbtu). Alberta based AECO natural gas pricing for 2009 decreased 49% to average $3.91 per GJ from $7.71 per GJ in 2008 (2007 – $6.26 per GJ). During 2009, natural gas pricing decreased due to a significant increase in production from shale gas reservoirs in the US, a significant decline in industrial demand caused by the onset of worldwide financial and economic events, and record storage levels in North America.

Operating, Royalty and Capital Costs

Strong commodity prices in recent years have resulted in increased demand for oilfield services worldwide. This has led to inflationary operating and capital cost pressures throughout the crude oil and natural gas industry, particularly related to drilling activities and oil sands developments.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants. In Alberta, GHG regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. The British Columbia carbon tax is currently being assessed at $15/tonne of CO_2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $20/tonne on July 1, 2010, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that six facilities in British Columbia will be included under the cap and trade system, based on a proposed 25 kt CO_2e threshold. Saskatchewan is expected to release GHG regulations in 2010 that would require the North Tangleflags in-situ heavy oil facility to meet a reduction target for its GHG emissions intensity. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005-2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. For Phase 2 (2008-2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. 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.

Legislation to regulate GHGs in the United States through a cap and trade system is currently before the US Congress, although there is no certainty as to the form or stringency of the final legislation. In the absence of legislation, the US Environmental Protection Agency ("EPA") is authorized under the Clean Air Act to regulate GHGs, although EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the US. Various states have enacted or are evaluating low carbon fuel standards, which may affect access to market for crude oil with higher emissions intensity.

Continued cost pressures and the final outcome of changes to environmental regulations may adversely impact the Company's future net earnings, cash flow and capital projects. For additional details, refer to the "Greenhouse Gas and Other Air Emissions" section of this MD&A.

The Alberta Government implemented changes to the Alberta Royalty Framework ("ARF") effective January 1, 2009. The ARF includes a number of changes to royalty rates for natural gas, conventional crude oil, and oil sands production. Under the ARF, royalties payable vary according to commodity prices and the productivity of wells. Changes to the Alberta royalty regime under the ARF include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout, depending on benchmark crude oil pricing. For additional details, refer to the "Royalties" section of this MD&A.

ANALYSIS OF CHANGES IN REVENUE, BEFORE ROYALTIES AND RISK MANAGEMENT ACTIVITIES

		Changes due to				**Changes due to**			
($ millions)	2007	Volumes	Prices	Other	2008	**Volumes**	**Prices**	**Other**	**2009**
North America									
Crude oil and NGLs	$ 5,847	$ (49)	$ 3,013	$ –	$ 8,811	**$ (424)**	**$ (2,649)**	**$ –**	**$ 5,738**
Natural Gas	4,302	(531)	914	–	4,685	**(598)**	**(1,852)**	**–**	**2,235**
	10,149	(580)	3,927	–	13,496	**(1,022)**	**(4,501)**	**–**	**7,973**
North Sea									
Crude oil and NGLs	1,575	(334)	512	–	1,753	**(344)**	**(465)**	**–**	**944**
Natural gas	22	(5)	(1)	–	16	**–**	**1**	**–**	**17**
	1,597	(339)	511	–	1,769	**(344)**	**(464)**	**–**	**961**
Offshore West Africa									
Crude oil and NGLs	751	(136)	280	–	895	**413**	**(436)**	**–**	**872**
Natural gas	25	5	19	–	49	**18**	**(26)**	**–**	**41**
	776	(131)	299	–	944	**431**	**(462)**	**–**	**913**
Subtotal									
Crude oil and NGLs	8,173	(519)	3,805	–	11,459	**(355)**	**(3,550)**	**–**	**7,554**
Natural gas	4,349	(531)	932	–	4,750	**(580)**	**(1,877)**	**–**	**2,293**
	12,522	(1,050)	4,737	–	16,209	**(935)**	**(5,427)**	**–**	**9,847**
Oil Sands Mining and Upgrading	–	–	–	–	–	**1,253**	**–**	**–**	**1,253**
Midstream	74	–	–	3	77	**–**	**–**	**(5)**	**72**
Intersegment eliminations and other (1)	(53)	–	–	(60)	(113)	**–**	**–**	**19**	**(94)**
Total	$ 12,543	$ (1,050)	$ 4,737	$ (57)	$ 16,173	**$ 318**	**$ (5,427)**	**$ 14**	**$ 11,078**

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

Revenue decreased 32% to $11,078 million for 2009 from $16,173 million for 2008 (2007 – $12,543 million). The decrease was primarily due to decreased realized crude oil and NGLs and natural gas prices company-wide.

For 2009, 17% of the Company's crude oil and natural gas revenue was generated outside of North America (2008 – 17%; 2007 – 19%). North Sea accounted for 9% of crude oil and natural gas revenue for 2009 (2008 – 11%; 2007 – 13%), and Offshore West Africa accounted for 8% of crude oil and natural gas revenue for 2009 (2008 – 6%; 2007 – 6%).

ANALYSIS OF DAILY PRODUCTION, BEFORE ROYALTIES

	2009	2008	2007
Crude oil and NGLs (bbl/d)			
North America – Conventional	**234,523**	243,826	246,779
North America – Oil Sands Mining and Upgrading	**50,250**	–	–
North Sea	**37,761**	45,274	55,933
Offshore West Africa	**32,929**	26,567	28,520
	355,463	315,667	331,232
Natural gas (mmcf/d)			
North America	**1,287**	1,472	1,643
North Sea	**10**	10	13
Offshore West Africa	**18**	13	12
	1,315	1,495	1,668
Total barrels of oil equivalent (boe/d)	**574,730**	564,845	609,206
Product mix			
Light/medium crude oil and NGLs	**21%**	22%	23%
Pelican Lake crude oil	**6%**	6%	6%
Primary heavy crude oil	**15%**	16%	15%
Thermal heavy crude oil	**11%**	12%	11%
Synthetic crude oil	**9%**	–	–
Natural gas	**38%**	44%	45%
Percentage of gross revenue (1) (excluding midstream revenue)			
Crude oil and NGLs	**75%**	68%	62%
Natural gas	**25%**	32%	38%

(1) Net of transportation and blending costs and excluding risk management activities.

ANALYSIS OF DAILY PRODUCTION, NET OF ROYALTIES

	2009	2008	2007
Crude oil and NGLs (bbl/d)			
North America – Conventional	**201,873**	207,933	210,769
North America – Oil Sands Mining and Upgrading	**48,833**	–	–
North Sea	**37,683**	45,182	55,825
Offshore West Africa	**29,922**	22,641	26,012
	318,311	275,756	292,606
Natural gas (mmcf/d)			
North America	**1,214**	1,225	1,378
North Sea	**10**	10	13
Offshore West Africa	**17**	11	11
	1,241	1,246	1,402
Total barrels of oil equivalent (boe/d)	**525,103**	483,541	526,193

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

Total production averaged 574,730 boe/d for 2009, a 2% increase from 564,845 boe/d for 2008 (2007 – 609,206 boe/d).

Total production of crude oil and NGLs before royalties increased 13% to 355,463 bbl/d for 2009 from 315,667 bbl/d for 2008 (2007 – 331,232 bbl/d). The increase in crude oil and NGLs production from 2008 was primarily due to the commencement of production from Horizon and the Olowi Field in Offshore Gabon and the restoration of some of the production in the Baobab Field in Offshore Côte d'Ivoire. Crude oil and NGLs production for 2009 was within the Company's previously issued guidance of 352,000 to 363,000 bbl/d.

Natural gas production continued to represent the Company's largest product offering, accounting for 38% of the Company's total production in 2009. Total natural gas production before royalties decreased 12% to 1,315 mmcf/d for 2009 from 1,495 mmcf/d for

2008 (2007 – 1,668 mmcf/d). The decrease in natural gas production from 2008 primarily reflected natural production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects. Natural gas production for 2009 exceeded the Company's previously issued guidance of 1,305 to 1,314 mmcf/d.

For 2010, annual production is forecasted to average between 400,000 and 445,000 bbl/d of crude oil and NGLs and between 1,117 and 1,185 mmcf/d of natural gas.

North America – Conventional

North America crude oil and NGLs production for 2009 decreased 4% to average 234,523 bbl/d from 243,826 bbl/d for 2008 (2007 – 246,779 bbl/d). The decrease in production from 2008 was primarily due to the cyclic nature of the Company's thermal production and was in line with expectations.

North America natural gas production for 2009 decreased 13% to average 1,287 mmcf/d from 1,472 mmcf/d for 2008 (2007 – 1,643 mmcf/d). The decrease in natural gas production from 2008 reflected production declines due to the Company's strategic decision to reduce natural gas drilling activity to focus on higher return crude oil projects.

North America – Oil Sands Mining and Upgrading

Horizon Phase 1 achieved first production of synthetic crude oil during 2009. Production averaged 50,250 bbl/d for 2009. Production volumes fluctuated throughout the year as the Company continued to stabilize and ramp up production.

North Sea

North Sea crude oil production for 2009 was 37,761 bbl/d, a decrease of 17% from 45,274 bbl/d for 2008 (2007 – 55,933 bbl/d) due to expected production decline.

Offshore West Africa

Offshore West Africa crude oil production for 2009 increased 24% to 32,929 bbl/d from 26,567 bbl/d for 2008 (2007 – 28,520 bbl/d). Production increased in 2009 due to additional volumes from the Baobab drilling program, which was completed in the second quarter, and new production from the Olowi Field in Offshore Gabon, offset by expected declines at Espoir.

Production volumes from the first platform at the Olowi Field continue to be below expectations and, as a result, the Company recognized a ceiling test impairment of $115 million at December 31, 2009. Drilling results and production data is being reviewed in order to develop appropriate remediation strategies and determine the impact on future production from the Field, the impact on recoverable reserves and the scope of the overall development plan. The Company continues drilling at the next scheduled platform with production targeted for the second quarter of 2010.

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 floating production, storage and offtake vessels as follows:

(bbl)	**2009**	2008	2007
North America – Conventional	**1,131,372**	761,351	1,097,526
North America – Oil Sands Mining and Upgrading (SCO)	**1,224,481**	–	–
North Sea	**713,112**	558,904	1,032,723
Offshore West Africa [(1)]	**51,103**	1,113,156	342,987
	3,120,068	2,433,411	2,473,236

(1) Prior period inventory volumes include one-time adjustments to sales volumes for MD&A reporting purposes only.

OPERATING HIGHLIGHTS – CONVENTIONAL

	2009	2008	2007
Crude oil and NGLs ($/bbl) (1)			
Sales price (2)	**$ 57.68**	$ 82.41	$ 55.45
Royalties	**6.73**	10.48	5.94
Production expense	**15.92**	16.26	13.34
Netback	**$ 35.03**	$ 55.67	$ 36.17
Natural gas ($/mcf) (1)			
Sales price (2)	**$ 4.53**	$ 8.39	$ 6.85
Royalties (3)	**0.32**	1.46	1.11
Production expense	**1.08**	1.02	0.91
Netback	**$ 3.13**	$ 5.91	$ 4.83
Barrels of oil equivalent ($/boe) (1)			
Sales price (2)	**$ 44.87**	$ 68.62	$ 49.05
Royalties	**4.72**	9.78	6.26
Production expense	**11.98**	11.79	9.75
Netback	**$ 28.17**	$ 47.05	$ 33.04

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

ANALYSIS OF PRODUCT PRICES – CONVENTIONAL

	2009	2008	2007
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 54.70**	$ 77.42	$ 49.16
North Sea	**$ 68.84**	$ 100.31	$ 74.99
Offshore West Africa	**$ 65.27**	$ 97.96	$ 71.68
Company average	**$ 57.68**	$ 82.41	$ 55.45
Natural gas ($/mcf) (1) (2)			
North America	**$ 4.51**	$ 8.41	$ 6.87
North Sea	**$ 4.66**	$ 4.09	$ 4.26
Offshore West Africa	**$ 6.11**	$ 10.03	$ 5.68
Company average	**$ 4.53**	$ 8.39	$ 6.85
Company average ($/boe) (1) (2)	**$ 44.87**	$ 68.62	$ 49.05

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

Realized crude oil and NGLs prices decreased 30% to average $57.68 per bbl for 2009 from $82.41 per bbl for 2008 (2007 – $55.45 per bbl). The decrease in 2009 was primarily a result of lower WTI and Brent benchmark crude oil prices during most of the year, partially offset by the impact of the narrowing of the Heavy Differential and the weaker Canadian dollar relative to the US dollar during 2009.

The Company's realized natural gas price decreased 46% to average $4.53 per mcf for 2009 from $8.39 per mcf for 2008 (2007 – $6.85 per mcf). The decrease in 2009 was primarily due to lower benchmark prices resulting from lower demand, as well as higher storage levels due to increased shale gas production in the US.

North America

North America realized crude oil prices decreased 29% to average $54.70 per bbl for 2009 from $77.42 per bbl for 2008 (2007 – $49.16 per bbl). The decrease in 2009 was due to decreased WTI benchmark pricing, partially offset by the impact of a narrower Heavy Differential, and a weaker Canadian dollar.

The Company continues to focus on its crude oil marketing strategy, including the development of 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 conversion capacity. During 2009, the Company contributed approximately 140,000 bbl/d of heavy crude oil blends to the WCS stream. The Company has entered into a 20-year transportation agreement to commit to ship 120,000 bbl/d of heavy sour crude oil on the proposed 500,000 bbl/d Keystone Pipeline US Gulf Coast expansion from Hardisty, Alberta to the US Gulf Coast. Contemporaneously, the Company also entered into a 20-year crude oil purchase and sales agreement to sell 100,000 bbl/d of heavy sour crude oil to a major US refiner. Deliveries under the agreements are expected to commence in 2012 upon completion of the pipeline expansion and are subject to Keystone's receipt of regulatory approval of the pipeline expansion.

In the first quarter of 2010, the Company announced, together with North West Upgrading Inc., the submission of a joint proposal to the Alberta Government to construct and operate a bitumen refinery near Redwater, Alberta. This proposal was submitted in response to a request for proposal under the Alberta Royalty Framework's Bitumen Royalty In Kind (BRIK) program.

North America realized natural gas prices decreased 46% to average $4.51 per mcf for 2009 from $8.41 per mcf for 2008 (2007 – $6.87 per mcf), primarily related to lower benchmark prices due to the impact of weather and storage levels.

Comparisons of the prices received for the Company's North America conventional production by product type were as follows:

(Yearly average)		2009		2008		2007
Wellhead Price (1) (2)						
Light/medium crude oil and NGLs (C$/bbl)	**$**	**57.02**	$	89.04	$	66.24
Pelican Lake crude oil (C$/bbl)	**$**	**55.52**	$	76.91	$	46.29
Primary heavy crude oil (C$/bbl)	**$**	**55.66**	$	74.91	$	43.77
Thermal heavy crude oil (C$/bbl)	**$**	**51.18**	$	71.89	$	43.49
Natural gas (C$/mcf)	**$**	**4.51**	$	8.41	$	6.87

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

North Sea

North Sea realized crude oil prices decreased 31% to average $68.84 per bbl for 2009 from $100.31 per bbl for 2008 (2007 – $74.99 per bbl). Realized crude oil prices per bbl in any particular period are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The decrease in realized crude oil prices in the North Sea from 2008 reflected weaker Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar.

Offshore West Africa

Offshore West Africa realized crude oil prices decreased 33% to average $65.27 per bbl for 2009 from $97.96 per bbl for 2008 (2007 – $71.68 per bbl). Realized crude oil prices per bbl in any particular period are dependant on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices at the time of lifting. The decrease in realized crude oil prices in Offshore West Africa from 2008 reflected weaker Brent benchmark pricing, partially offset by the impact of the weaker Canadian dollar.

ROYALTIES – CONVENTIONAL

		2009		2008		2007
Crude oil and NGLs ($/bbl) (1)						
North America	**$**	**7.93**	$	11.99	$	7.19
North Sea	**$**	**0.14**	$	0.21	$	0.14
Offshore West Africa	**$**	**5.79**	$	14.81	$	6.40
Company average	**$**	**6.73**	$	10.48	$	5.94
Natural gas ($/mcf) (1)						
North America (2)	**$**	**0.32**	$	1.47	$	1.12
Offshore West Africa	**$**	**0.53**	$	1.52	$	0.51
Company average	**$**	**0.32**	$	1.46	$	1.11
Company average ($/boe) (1)	**$**	**4.72**	$	9.78	$	6.26
Percentage of revenue (3)						
Crude oil and NGLs		**12%**		13%		11%
Natural gas (2)		**7%**		17%		16%
Boe		**11%**		14%		13%

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.
(3) Net of transportation and blending costs and excluding risk management activities.

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 ("net profit"). For 2008 and prior years, royalties were calculated as 1% of gross revenues until the Company's capital investments in the applicable project were fully recovered, at which time the royalty increased to 25% of net profit. Effective January 1, 2009, changes to the Alberta royalty regime under the ARF include the implementation of a sliding scale for oil sands royalties ranging from 1% to 9% on a gross revenue basis pre-payout and 25% to 40% on a net revenue basis post-payout depending on benchmark crude oil pricing.

In addition, effective January 1, 2009, new royalty formulas under the ARF for conventional crude oil and natural gas operate on sliding scales ranging up to 50%, determined by commodity prices and well productivity.

In March 2009, the Government of Alberta announced new incentive programs to stimulate activity in Alberta. These programs provide for:

- A royalty credit of $200 per meter on new conventional crude oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, to a maximum of 10% of conventional Crown royalties paid in Alberta.
- Reduced royalty rates that set the maximum royalty at 5% for the first 12 months of production, up to a maximum of 50,000 boe or 500 mmcfe, for new conventional crude oil and natural gas wells that commence production between April 1, 2009 and March 31, 2010.

In June 2009, the Government of Alberta extended the two incentive programs described above by one year, to March 31, 2011.

Effective September 1, 2009, the Province of British Columbia announced an oil and gas stimulus package that includes:

- A one-year, 2% royalty rate for all natural gas wells drilled between September 1, 2009 and June 30, 2010. Qualifying wells must commence production before December 31, 2010.
- A permanent increase of 15% in the existing royalty holiday credits for the Deep Royalty Program.
- Permanent qualification of horizontal wells drilled to a vertical depth between 1,900 and 2,300 meters into the Deep Royalty Program.
- An additional $50 million allocation for the Infrastructure Royalty Credit Program to stimulate investment in oil and gas roads and pipelines.

Crude oil and NGLs royalties for 2009 compared to 2008 reflected weaker realized crude oil prices and the impact of the ARF and averaged approximately 14% of gross revenues for 2009 compared to 15% for 2008 (2007 – 15%). North America crude oil and NGLs royalties per bbl are anticipated to average 17% to 19% of gross revenue for 2010.

Natural gas royalties averaged approximately 7% of gross revenues for 2009 compared to 18% for 2008 (2007 – 16%), primarily due to lower benchmark natural gas prices and the impact of the ARF. North America natural gas royalties per mcf are anticipated to average 11% to 13% of gross revenue for 2010.

North Sea

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

Offshore West Africa

Under the terms of Production Sharing Contracts ("PSCs"), royalty rates fluctuate based on realized commodity pricing, capital costs, and the timing of liftings from each field. Royalty rates as a percentage of revenue averaged approximately 9% for 2009 compared to 15% for 2008 (2007 – 9%). Offshore West Africa royalty rates are anticipated to average 7% to 9% of gross revenue for 2010.

PRODUCTION EXPENSE – CONVENTIONAL

	2009	2008	2007
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 14.63**	$ 14.96	$ 12.26
North Sea	**$ 26.98**	$ 26.29	$ 20.78
Offshore West Africa	**$ 12.83**	$ 10.29	$ 8.32
Company average	**$ 15.92**	$ 16.26	$ 13.34
Natural gas ($/mcf) (1)			
North America	**$ 1.07**	$ 1.00	$ 0.90
North Sea	**$ 2.16**	$ 2.51	$ 2.17
Offshore West Africa	**$ 1.23**	$ 1.61	$ 1.48
Company average	**$ 1.08**	$ 1.02	$ 0.91
Company average ($/boe) (1)	**$ 11.98**	$ 11.79	$ 9.75

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

North America

North America crude oil and NGLs production expense for 2009 decreased 2% to $14.63 per bbl from $14.96 per bbl for 2008 (2007 – $12.26 per bbl). The decrease in production expense per bbl from 2008 was primarily a result of the Company's focus on optimizing service costs, together with lower power prices and cost of natural gas for fuel for the Company's thermal operations partially offset by the impact of increased property tax.

North America natural gas production expense for 2009 increased 7% to $1.07 per mcf from $1.00 per mcf for 2008 (2007 – $0.90 per mcf). The increase in production expense per mcf from 2008 was primarily a result of the impact of lower production volumes on fixed costs, offset by reductions due to the Company's focus on optimizing service costs and lower power prices.

North Sea

North Sea crude oil production expense increased on a per barrel basis from 2008 primarily due to lower production volumes on a relatively fixed operating cost base and the weakening of the Canadian dollar against the UK pound sterling.

Offshore West Africa

Offshore West Africa crude oil production expense increased on a per barrel basis from 2008. Production expense was impacted by the timing of liftings of each field and higher operating costs per barrel in Gabon.

DEPLETION, DEPRECIATION AND AMORTIZATION – CONVENTIONAL

($ millions, except per boe amounts) (1)	2009	2008	2007
North America	**$ 2,060**	$ 2,236	$ 2,350
North Sea	**261**	317	340
Offshore West Africa	**335**	132	165
Expense	**$ 2,656**	$ 2,685	$ 2,855
$/boe	**$ 13.82**	$ 12.97	$ 12.84

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

Depletion, Depreciation and Amortization ("DD&A") expense for 2009 decreased slightly to $2,656 million from $2,685 million for 2008 (2007 – $2,855 million), primarily due to the impact of lower sales volumes offset by the impact of a ceiling test impairment related to Gabon, Offshore West Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – CONVENTIONAL

($ millions, except per boe amounts) (1)	2009	2008	2007
North America	**$ 41**	$ 42	$ 38
North Sea	**24**	27	30
Offshore West Africa	**4**	2	2
Expense	**$ 69**	$ 71	$ 70
$/boe	**$ 0.36**	$ 0.34	$ 0.32

(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. Accretion expense in 2009 was comparable to 2008.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

FINANCIAL METRICS

($/bbl) (1)	2009	2008	2007
SCO sales price (2)	**$ 70.83**	$ –	$ –
Bitumen value for royalty purposes	**$ 56.57**	$ –	$ –
Bitumen royalties (3)	**$ 2.15**	$ –	$ –

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and excluding risk management activities.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

PRODUCTION COSTS

The following tables provide reconciliations of Oil Sands Mining and Upgrading production costs to the Segmented Information disclosed in note 16 to the Company's consolidated financial statements.

($ millions)	2009	2008	2007
Cash costs, excluding natural gas costs	**$ 599**	$ –	$ –
Natural gas costs	**84**	–	–
Total cash production costs	**$ 683**	$ –	$ –

($/bbl) (1)	2009	2008	2007
Cash costs, excluding natural gas costs	$ 34.97	$ –	$ –
Natural gas costs	4.92	–	–
Total cash production costs	$ 39.89	$ –	$ –
Sales (bbl/d)	46,896	–	–

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

First sales from Horizon occurred in the second quarter of 2009.

Production expense in 2009 reflected the effects of the commencement of operations. Total cash production costs averaged $39.89 per bbl in 2009. Cash production costs in 2009 reflected the impact of maintenance costs related to premature equipment failures and overall plant reliability. Cash production costs are targeted to average $31.00 to $37.00 per bbl in 2010.

($ millions)	2009	2008	2007
Depreciation, depletion and amortization	$ 187	$ –	$ –
Asset retirement obligation accretion	21	–	–
Total	$ 208	$ –	$ –

($/bbl) (1)	2009	2008	2007
Depreciation, depletion and amortization	$ 10.95	$ –	$ –
Asset retirement obligation accretion	1.22	–	–
Total	$ 12.17	$ –	$ –

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

During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs has ceased, and depletion, depreciation and amortization of these assets has commenced. Depletion, depreciation and amortization included the disposal of a portion of the tailings line pipe related to premature wear.

MIDSTREAM

($ millions)	2009	2008	2007
Revenue	$ 72	$ 77	$ 74
Production expense	19	25	22
Midstream cash flow	53	52	52
Depreciation	9	8	8
Segment earnings before taxes	$ 44	$ 44	$ 44

The Company's midstream assets consist of three crude oil pipeline systems and a 50% working interest in an 84-megawatt cogeneration plant at Primrose. Approximately 80% 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 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.

ADMINISTRATION EXPENSE

($ millions, except per boe amounts) (1)	2009	2008	2007
Expense	$ 181	$ 180	$ 208
$/boe	$ 0.87	$ 0.87	$ 0.93

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

Administration expense for 2009 was comparable to 2008. Administration expense on a boe basis in 2009 includes sales volumes associated with the commencement of Horizon.

STOCK-BASED COMPENSATION

($ millions)	2009	2008	2007
Expense (recovery)	$ 355	$ (52)	$ 193

The Company's Stock Option Plan (the "Option Plan") provides current employees (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The design of the Option Plan balances the need for a long-term compensation program to retain employees with the benefits of reducing the impact of dilution on current Shareholders and the reporting of the obligations associated with stock options. Transparency of the cost of the Option Plan is increased as changes in the intrinsic value of outstanding stock options are recognized each period. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company recorded a $355 million ($261 million after-tax) stock-based compensation expense during 2009 primarily as a result of normal course graded vesting of options granted in prior periods, the impact of vested options exercised or surrendered during the year, and the 56% increase in the Company's share price for the year ended December 31, 2009 (December 31, 2009 – $76.00; December 31, 2008 – $48.75; December 31, 2007 – $72.58; December 31, 2006 – $62.15). As required by Canadian GAAP, the Company records a liability for potential cash payments to settle its outstanding employee stock options each reporting period based on the difference between the exercise price of the stock options and the market price of the Company's common shares, pursuant to a graded vesting schedule. For the year ended December 31, 2009, the Company capitalized $2 million in stock-based compensation to Oil Sands Mining and Upgrading (2008 – $23 million recovery; 2007 – $58 million capitalized).

The stock-based compensation liability reflected the Company's potential cash liability should all the vested options be surrendered for a cash payout at the market price on December 31, 2009. In periods when substantial stock price changes occur, the Company's earnings are subject to significant volatility. The Company utilizes its stock-based compensation plan to attract and retain employees in a competitive environment. All employees participate in this plan.

For the year ended December 31, 2009, the Company paid $94 million for stock options surrendered for cash settlement (2008 – $207 million; 2007 – $375 million).

INTEREST EXPENSE

($ millions, except per boe amounts and interest rates) (1)	2009	2008	2007
Expense, gross	$ 516	$ 609	$ 632
Less: capitalized interest, Oil Sands Mining and Upgrading	106	481	356
Expense, net	$ 410	$ 128	$ 276
$/boe	$ 1.96	$ 0.62	$ 1.24
Average effective interest rate	4.3%	5.1%	5.5%

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

Gross interest expense decreased from 2008 primarily due to lower debt levels and lower variable interest rates and reflected the impact of fluctuations in foreign exchange rates on US dollar denominated debt. The Company's average effective interest rate decreased from the comparable period in 2008 primarily due to lower variable interest rates.

During 2009, interest capitalization ceased on Horizon Phase 1 as the Phase 1 assets were completed and available for their intended use, increasing net interest expense accordingly.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	2009	2008	2007
Crude oil and NGLs financial instruments	$ (1,330)	$ 2,020	$ 505
Natural gas financial instruments	(33)	(21)	(343)
Foreign currency contracts	110	(139)	–
Realized (gain) loss	$ (1,253)	$ 1,860	$ 162
Crude oil and NGLs financial instruments	$ 2,039	$ (3,104)	$ 1,244
Natural gas financial instruments	(58)	16	156
Foreign currency contracts	10	(2)	–
Unrealized loss (gain)	$ 1,991	$ (3,090)	$ 1,400
Net loss (gain)	$ 738	$ (1,230)	$ 1,562

Complete details related to outstanding derivative financial instruments at December 31, 2009 are disclosed in note 13 to the Company's consolidated financial statements.

The commodity derivative financial instruments currently outstanding have not been designated as hedges for accounting purposes (the "non-designated hedges"). The fair value of these non-designated hedges is based on prevailing forward commodity prices in effect at the end of each reporting period and is reflected in risk management activities in consolidated net earnings. The cash settlement amount of the commodity derivative financial instruments may vary materially depending upon the underlying crude oil and natural gas prices at the time of final settlement, as compared to their mark-to-market value at December 31, 2009.

Due to changes in crude oil and natural gas forward pricing and the reversal of prior period unrealized gains and losses, the Company recorded a net unrealized loss of $1,991 million ($1,437 million after-tax) on its risk management activities for the year ended December 31, 2009 (2008 – $3,090 million unrealized gain, $2,112 million after-tax; 2007 – $1,400 million unrealized loss, $977 million after-tax).

FOREIGN EXCHANGE

($ millions)	2009	2008	2007
Net realized loss (gain)	$ 30	$ (114)	$ 53
Net unrealized (gain) loss [(1)]	(661)	832	(524)
Net (gain) loss	$ (631)	$ 718	$ (471)

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

As a result of foreign currency translation, the Company's operating results are affected by the fluctuations in the exchange rates between the Canadian dollar, US dollar, and UK pound sterling. A majority 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 and future income tax liabilities 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 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 unrealized foreign exchange gain in 2009 was primarily related to the strengthening Canadian dollar in relation to the US dollar with respect to the US dollar denominated debt, partially offset by the impact of the re-measurement of North Sea future income tax liabilities denominated in UK pounds sterling to US dollars. Included in the net unrealized gain for the year ended December 31, 2009 was an unrealized loss of $338 million (2008 – $449 million unrealized gain, 2007 – $351 million unrealized loss) related to the impact of cross currency swap hedges. The net realized foreign exchange loss for 2009 was primarily due to the result of foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US dollar denominated debt. The Canadian dollar ended the year at US$0.9555 compared to US$0.8166 at December 31, 2008 (December 31, 2007 – US$1.0120).

TAXES

($ millions, except income tax rates)	2009	2008	2007
Current	$ 91	$ 245	$ 121
Deferred	15	(67)	44
Taxes other than income tax	$ 106	$ 178	$ 165
North America [(1)]	$ 28	$ 33	$ 96
North Sea	278	340	210
Offshore West Africa	82	128	74
Current income tax	388	501	380
Future income tax	(99)	1,607	(456)
	289	2,108	(76)
Income tax rate and other legislative changes [(2)(3)(4)]	19	41	864
	$ 308	$ 2,149	$ 788
Effective income tax rate before income tax rate and other legislative changes	24.3%	27.8%	32.2%

(1) Includes North America Conventional Crude Oil and Natural Gas, Midstream, and Oil Sands Mining and Upgrading segments.

(2) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions substantively enacted or enacted during 2009.

(3) Includes the effects of one time recoveries of $19 million due to British Columbia corporate income tax rate reductions and $22 million due to Côte d'Ivoire corporate income tax rate reductions substantively enacted or enacted during 2008.

(4) Includes the effect of one time recoveries of $864 million due to Canadian Federal income tax rate reductions and other legislative changes substantively enacted or enacted during 2007.

Taxes other than income tax primarily includes current and deferred PRT, which is charged on certain fields in the North Sea at the rate of 50% of net operating income, after allowing for certain deductions including related capital and abandonment expenditures.

Taxable income from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. North America current income taxes have been provided on the basis of this corporate structure. In addition, current income taxes in each business segment will vary depending on available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

For 2010, based on budgeted prices and the current availability of tax pools, the Company expects to incur current income tax expense in Canada of $450 million to $550 million and in the North Sea and Offshore West Africa of $220 million to $260 million.

NET CAPITAL EXPENDITURES (1)

($ millions)	2009	2008	2007
Expenditures on property, plant and equipment			
Net property acquisitions (dispositions)	**$ 6**	$ 336	$ (39)
Land acquisition and retention	**77**	86	95
Seismic evaluations	**73**	107	124
Well drilling, completion and equipping	**1,244**	1,664	1,642
Production and related facilities	**977**	1,282	1,205
Total net reserve replacement expenditures	**2,377**	3,475	3,027
Oil Sands Mining and Upgrading:			
Horizon Phase 1 construction costs	**69**	2,732	2,740
Horizon Phase 1 commissioning costs and other	**202**	364	–
Horizon Phases 2/3 construction costs	**104**	336	124
Capitalized interest, stock-based compensation and other	**98**	480	437
Sustaining capital	**80**	–	–
Total Oil Sands Mining and Upgrading (2)	**553**	3,912	3,301
Midstream	**6**	9	6
Abandonments (3)	**48**	38	71
Head office	**13**	17	20
Total net capital expenditures	**$ 2,997**	$ 7,451	$ 6,425
By segment			
North America	**$ 1,663**	$ 2,344	$ 2,428
North Sea	**168**	319	439
Offshore West Africa	**544**	811	159
Other	**2**	1	1
Oil Sands Mining and Upgrading	**553**	3,912	3,301
Midstream	**6**	9	6
Abandonments (3)	**48**	38	71
Head office	**13**	17	20
Total	**$ 2,997**	$ 7,451	$ 6,425

(1) Net capital expenditures exclude adjustments related to differences between carrying value and tax value, and other fair value adjustments.
(2) Net expenditures for Oil Sands Mining and Upgrading assets also include the impact of intersegment eliminations.
(3) Abandonments represent expenditures to settle ARO and have been reflected as capital expenditures in this table.

The Company's operating 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 regions where it can dominate the land base and infrastructure. 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 dominating infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for 2009 were $2,997 million compared to $7,451 million for 2008 (2007 – $6,425 million). The decrease in capital expenditures from the prior year reflects the completion of Horizon Phase 1 construction. Capital expenditures were also impacted by the effects of an overall strategic reduction in the North America natural gas drilling program.

Drilling Activity (number of wells)	2009	2008	2007
Net successful natural gas wells	**109**	269	383
Net successful crude oil wells	**644**	682	592
Dry wells	**46**	39	93
Stratigraphic test / service wells	**329**	131	254
Total	**1,128**	1,121	1,322
Success rate (excluding stratigraphic test / service wells)	**94%**	96%	91%

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 58% of the total capital expenditures for the year ended December 31, 2009 compared to approximately 32% for 2008 (2007 – 39%).

During 2009, the Company targeted 117 net natural gas wells, including 21 wells in Northeast British Columbia, 39 wells in the Northern Plains region, 47 wells in Northwest Alberta, and 10 wells in the Southern Plains region. The Company also targeted 676 net crude oil wells during the year. The majority of these wells were concentrated in the Company's crude oil Northern Plains region where 496 primary heavy crude oil wells, 60 Pelican Lake crude oil wells, 82 thermal crude oil wells and 2 light crude oil wells were drilled. Another 36 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, a low natural gas price, and as a result of royalty changes under the ARF, natural gas drilling activities have been reduced. Deferred natural gas well locations have been retained in the Company's prospect inventory.

As part of the phased expansion of its In-Situ Oil Sands Assets, the Company is continuing to develop its Primrose thermal projects. During 2009, the Company drilled 82 thermal oil wells, and 36 stratigraphic test wells and observation wells. Overall Primrose thermal production for 2009 was approximately 64,000 bbl/d (2008 – 65,000 bbl/d; 2007 – 64,000 bbl/d). The Primrose East Expansion, a new facility located 15 kilometers from the existing Primrose South steam plant and 25 kilometers from the Wolf Lake central processing facility, was completed and first steaming commenced in September 2008, with first production achieved in the fourth quarter of 2008. During the first quarter of 2009, operational issues on one of the pads caused steaming to cease on all well pads in the Primrose East project area. During 2009, upon receipt of regulatory approval, the Company began diagnostic steaming and is continuing to work on resolving the issue.

The next planned phase of the Company's In-Situ Oil Sands Assets expansion is the Kirby project located 120 kilometers north of the existing Primrose facilities. During 2007, the Company filed a combined application and Environmental Impact Assessment for this project with Alberta Environment and the Alberta Energy and Utilities Board. Final corporate sanction and project scope is targeted for late 2010. Currently, the Company is proceeding with the detailed engineering and design work.

Development of new pads and tertiary recovery conversion projects at Pelican Lake continued as expected throughout 2009. Drilling consisted of 60 horizontal crude oil wells, with plans to drill 147 additional horizontal crude oil wells in 2010. The response from the water and polymer flood projects continues to be positive. Pelican Lake production averaged approximately 37,000 bbl/d in 2009 (2008 – 37,000 bbl/d; 2007 – 34,000 bbl/d).

For 2010, the Company's overall drilling activity in North America is expected to comprise approximately 93 natural gas wells and 956 crude oil wells, excluding stratigraphic and service wells.

Oil Sands Mining and Upgrading

With construction completed, Horizon Phase 1 assets are now available for their intended use. Accordingly, capitalization of all associated development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased, and depletion, depreciation and amortization of these assets commenced.

Production was lower than anticipated due to a number of challenges encountered in the third and fourth quarter. The challenges primarily relate to:

- Premature equipment failures in the Ore Preparation Plant, Primary Upgrading, the Naphtha Recovery Unit and the Sulphur Plant;
- Ore processing challenges arising in September resulting from a higher percentage of clays in the second mine bench and the lack of available blending materials from other mine benches associated with early mine operations; and
- Equipment failure in the hydrogen plant, requiring a shutdown for an extended period of time, and issues with one of the coker furnaces.

Engineering and procurement is underway for Tranche 2 of the Phase 2/3 expansion with a focus on increasing reliability and uptime. Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

North Sea

During 2009, the Company drilled 0.9 net oil wells and 0.3 net exploration wells at Deep Banff, which did not find commercial reserves. Focus continued on lowering costs and high grading infill drilling opportunities ahead of the planned restart of platform drilling operations in the second quarter of 2010.

The Company also completed planned maintenance turnarounds at four of its five Platform installations on time and on budget.

Offshore West Africa

The Company drilled 6.1 net wells during 2009.

The Company completed the Baobab drilling program in the first quarter of 2009, adding approximately 10,000 bbl/d net to the Company.

Progress on the Facility Upgrade Project at Espoir to increase processing capacity of the Floating Production Storage and Offtake Vessel ("FPSO") has reverted to the original schedule to accommodate effective utilization of the installation vessel at Olowi.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		2009		2008		2007
Working capital (deficit) (1)	$	**(514)**	$	392	$	(1,382)
Long-term debt (2) (3)	$	**9,658**	$	13,016	$	10,940
Shareholders' equity						
Share capital	$	**2,834**	$	2,768	$	2,674
Retained earnings		**16,696**		15,344		10,575
Accumulated other comprehensive (loss) income		**(104)**		262		72
Total	$	**19,426**	$	18,374	$	13,321
Debt to book capitalization (3) (4)		**33%**		41%		45%
Debt to market capitalization (3) (5)		**19%**		33%		22%
After tax return on average common shareholders' equity (6)		**8%**		33%		22%
After tax return on average capital employed (3) (7)		**6%**		19%		12%

(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 (2009 – $nil; 2008 – $420 million; 2007 – $nil).
(3) Long-term debt at December 31, 2009 and 2008 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 year; as a percentage of average common shareholders' equity for the year.
(7) Calculated as net earnings plus after-tax interest expense for the year; as a percentage of average capital employed. Average capital employed is the average shareholders' equity and current and long-term debt for the year, including $12,855 million in average capital employed related to the Horizon Oil Sands (2008 – $10,678 million; 2007 – $7,001 million).

At December 31, 2009, 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 is dependent on factors discussed in the "Risks and Uncertainties" section of this MD&A. The Company's ability to renew existing bank credit facilities and raise new debt is also dependent upon these factors, as well as 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 on-going 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.

During 2009, the Company repaid $2,350 million remaining on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation and cancelled the facility. At December 31, 2009, the Company had $2,004 million of available credit under its bank credit facilities. The Company's current debt ratings are BBB (high) with a stable trend by DBRS Limited, Baa2 with a stable outlook by Moody's Investors Service and BBB with a stable outlook by Standard & Poor's.

Further details related to the Company's long-term debt at December 31, 2009 are discussed below and in note 5 to the Company's audited annual consolidated financial statements.

Long-term debt was $9,658 million at December 31, 2009, resulting in a debt to book capitalization level of 33% as at December 31, 2009 (December 31, 2008 – 41%; December 31, 2007 – 45%). This ratio is below the 35% to 45% range targeted by management. The Company remains committed to maintaining a strong balance sheet and flexible capital structure. The Company has hedged a portion of its crude oil and natural gas production for 2010 at prices that protect investment returns to ensure ongoing balance sheet strength and the completion of its capital expenditure programs.

During 2009, the Company filed new base shelf prospectuses that allow for the issue of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

The Company's commodity hedging program reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditures programs. This program 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 program, the purchase of crude oil put options is in addition to the above parameters. As at December 31, 2009, in accordance with the policy, approximately 39% of budgeted crude oil and approximately 17% of budgeted natural gas volumes were hedged using collars for 2010.

Further details related to the Company's commodity related derivative financial instruments outstanding at December 31, 2009, are discussed in note 13 to the Company's audited annual consolidated financial statements.

Share Capital

As at December 31, 2009, there were 542,327,000 common shares outstanding and 32,106,000 stock options outstanding. As at March 3, 2010, the Company had 542,655,000 common shares outstanding and 30,702,000 stock options outstanding.

The Company did not renew its Normal Course Issuer Bid during 2009. During 2008 and 2009, the Company did not purchase any common shares for cancellation under the programs then in place.

On March 3, 2010, the Company's Board of Directors approved an increase in the annual dividend declared by the Company to $0.60 per common share for 2010. The increase represents a 43% increase from the prior year. The dividend policy undergoes a periodic review by the Board of Directors and is subject to change. In March 2009, an increase in the annual dividend paid by the Company to $0.42 per common share was approved for 2009. The increase represented a 5% increase from 2008.

On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a Notice of Intention to purchase by way of normal course issuer bid up to 2.5% of the Company's issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

Share Split

On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

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. These commitments primarily relate to firm commitments for gathering, processing and transmission services; operating leases relating to offshore FPSOs, drilling rigs and office space; expenditures relating to ARO; as well as long-term debt and interest payments. As at December 31, 2009, no entities were consolidated under CICA Handbook Accounting Guideline 15, "Consolidation of Variable Interest Entities". The following table summarizes the Company's commitments as at December 31, 2009:

($ millions)	2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$ 207	$ 162	$ 136	$ 125	$ 126	$ 1,051
Offshore equipment operating lease	$ 155	$ 124	$ 103	$ 102	$ 101	$ 261
Offshore drilling	$ 49	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 16	$ 20	$ 21	$ 31	$ 39	$ 6,479
Long-term debt (2)	$ 400	$ 419	$ 366	$ 819	$ 366	$ 5,424
Interest expense (3)	$ 473	$ 451	$ 415	$ 370	$ 350	$ 4,779
Office leases	$ 25	$ 19	$ 3	$ 2	$ 2	$ –
Other	$ 271	$ 67	$ 23	$ 15	$ 12	$ 34

(1) Amounts represent management's estimate of the future undiscounted payments to settle ARO related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010-2014 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

(2) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities.

(3) Interest expense amounts represent the scheduled fixed rate and variable rate cash payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates as of December 31, 2009.

LEGAL PROCEEDINGS

The Company is defendant and plaintiff in a number of legal actions. 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 year ended December 31, 2009 the Company retained qualified independent reserves evaluators, Sproule Associates Limited ("Sproule"), and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company's proved, as well as probable crude oil, synthetic crude oil, bitumen, natural gas, coal bed methane, and NGLs reserves and prepare Evaluation Reports on these reserves. Sproule evaluated and reviewed all of the Company's crude oil, bitumen, natural gas, coal bed methane and NGLs reserves. GLJ evaluated all of the synthetic crude oil reserves related to the Company's oil sands mine. The Company has been granted an exemption from certain provisions of National Instrument 51-101 – "Standards of Disclosure for 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. This exemption allows the Company to substitute SEC requirements under Regulations S-K and S-X for certain disclosures required under NI 51-101. On December 31, 2008, the SEC released its final rules for the modernization of oil and gas reporting ("Final Rule"). The material changes include the ability to include oil sands mining as an oil and gas activity, ability to use reliable technology to establish undeveloped reserves, the optional ability to report probable reserves, the requirement to track undeveloped locations, and the directive to use 12-month average prices and current costs. These resulting changes are more in line with NI 51-101, however, there are material differences to the type of volumes disclosed and the basis from which the volumes are determined. NI 51-101 requires gross reserves and future net revenue under forecast pricing and costs, however, the SEC, as discussed, requires disclosure of net reserves, after royalties, using 12-month average prices and current costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

The Company annually discloses proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs as mandated by the SEC in the supplementary oil and gas information section of the Company's Annual Report and in its annual Form 40-F filing with the SEC.

The following tables summarize the Company's proved crude oil and natural gas reserves, net of royalties, as at December 31, 2009 and 2008:

Crude oil and NGLs (mmbbl)	**Synthetic Crude Oil** (1)	**Bitumen** (2)	**Other Oil & NGLs**	**North America Total**	**North Sea**	**Offshore West Africa**	**Total**
Net proved reserves							
Reserves, December 31, 2008	–	690	258	948	256	142	1,346
Extensions and discoveries	–	24	6	30	–	–	30
Improved recovery	–	8	75	83	–	–	83
SEC Reliable Technology (3)	–	7	–	7	–	–	7
SEC Rule Transition (4)	1,650	–	–	1,650	–	–	1,650
Purchases of reserves in place	–	–	1	1	–	–	1
Sales of reserves in place	–	–	–	–	–	–	–
Production	–	(49)	(24)	(73)	(14)	(11)	(98)
Economic revisions due to prices	–	(64)	(8)	(72)	57	(4)	(19)
Revisions of prior estimates	–	79	11	90	(59)	(4)	27
Reserves, December 31, 2009	**1,650**	**695**	**319**	**2,664**	**240**	**123**	**3,027**

(1) Prior to December 31, 2009, the Company's Horizon SCO reserves were reported separately in accordance with SEC's Industry Guide 7. With SEC's Final Rule in effect January 1, 2010, this synthetic crude oil is now included in the Company's crude oil and natural gas reserve totals.

(2) Bitumen as defined by the SEC, under the Final Rule, "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 included. Prior to December 31, 2009, these numbers would have been included within the Company's conventional crude oil and NGL totals.

(3) SEC reliable technology accounts for reserve volumes added due to the reserve rule changes.

(4) For continuity purposes, with respect to the transition from Industry Guide 7 into SEC's Final Rule, the following SCO table has been provided to illustrate the changes in the Company's Horizon SCO reserves for the 2009 year.

Horizon SCO reserves (mmbbl)	Net Proved (mmbl)
Reserves, December 31, 2008	1,946
Production	(18)
Economic revisions due to prices	(307)
Revisions of prior estimates	29
Reserves, December 31, 2009	1,650

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2008	3,523	67	94	3,684
Extensions and discoveries	92	–	–	92
Improved recovery	11	–	–	11
SEC Reliable Technology	–	–	–	–
Purchases of reserves in place	15	–	–	15
Sales of reserves in place	(6)	–	–	(6)
Production	(443)	(4)	(6)	(453)
Economic revisions due to prices	(335)	12	(4)	(327)
Revisions of prior estimates	170	(8)	1	163
Reserves, December 31, 2009	**3,027**	**67**	**85**	**3,179**

The Company's net proved crude oil and NGLs reserves at December 31, 2009, excluding synthetic crude oil, totaled 1,377 mmbbl. Approximately 132% of the production was replaced by reserve additions and revisions during 2009. Additions resulting from exploration and development and acquisition activities amounted to 121 mmbbl, while net positive revisions amounted to 8 mmbbl.

The Company's net proved natural gas reserves, net of royalties, at December 31, 2009 totaled 3,179 bcf. Additions related to exploration, development, acquisition and dispostion activities amounted to 112 bcf, while net negative revisions amounted to 164 bcf. This net loss is largely due to the change in price from year end 2008 to year end 2009.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of Sproule and GLJ to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and net present value of remaining synthetic crude oil, crude oil, NGLs and natural gas reserves.

Additional reserves disclosure is annually disclosed in the supplementary oil and gas information of the Company's Annual Report.

RISKS AND UNCERTAINTIES

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

- Economic risk of finding, producing and replacing reserves 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;
- 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;
- Success of exploration and development activities;
- Timing and success of integrating the business and operations of acquired companies;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts;
- 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 the majority of sales are based in US dollars;
- Environmental impact risk associated with exploration and development activities, including GHG;
- Risk of catastrophic loss due to fire, explosion or acts of nature;
- Geopolitical risks associated with changing governmental policies, social instability and other political, economic or diplomatic developments in the Company's operations;
- Future legislative and regulatory developments related to environmental regulation;
- Reservoir quality;
- The ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisition;
- Potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdations where the Company has operations;

- Changing royalty regimes;
- Business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; 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 to an acceptable level. 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. Substantially all of the Company's accounts receivables are due within normal trade terms. Derivative financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. 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 detail regarding the Company's risks and uncertainties, refer to the Company's Annual Information Form.

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 operating facilities;
- Continued evaluation of new technologies to reduce environmental impacts;
- Development and implementation of a tailings management plan; and
- CO_2 reduction programs including the injection of CO_2 into tailings and for use in enhanced oil recovery.

For 2009, the Company's capital expenditures included $48 million for abandonment expenditures (2008 – $38 million; 2007 – $71 million).

The Company's estimated undiscounted ARO at December 31, 2009 was as follows:

Estimated ARO, undiscounted ($ millions)	2009	2008
North America, Conventional	$ 3,346	$ 3,072
North America, Oil Sands Mining and Upgrading (1)	1,485	93
North Sea	1,522	1,216
Offshore West Africa	253	93
	6,606	4,474
North Sea PRT recovery	(568)	(529)
	$ 6,038	$ 3,945

(1) Prior period amounts have been reclassified to conform to the presentation adopted in 2009.

The estimate of ARO is based on estimates of future costs to abandon and restore wells, production facilities and offshore production platforms. Factors that affect costs include number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs in accordance with present legislation and industry operating practice. The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates. The future abandonment costs incurred in the North Sea are estimated to result in a PRT recovery of $568 million (2008 – $529 million; 2007 – $555 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The expected PRT recovery reduces the Company's net undiscounted abandonment liability to $6,038 million (2008 – $3,945 million).

GREENHOUSE GAS AND OTHER AIR EMISSIONS

The Company, through the Canadian Association of Petroleum Producers ("CAPP"), is working with 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, targeted research and development while not impacting competitiveness.

In Canada, the Federal Government has indicated its intent to develop regulations that would be in effect in the near term to address industrial GHG emissions, as part of the national GHG reduction target. The Federal Government has also outlined national and sectoral reduction targets for several categories of air pollutants.

In Alberta, GHG reduction regulations came into effect July 1, 2007, affecting facilities emitting more than 100 kilotonnes of CO_2e annually. Two of the Company's facilities, the Primrose/Wolf Lake in-situ heavy crude oil facilities and the Hays sour natural gas plant, fall under the regulations. The British Columbia carbon tax is currently being assessed at $15/tonne of CO_2e on fuel consumed and gas flared in the province. This rate is scheduled to increase to $20/tonne on July 1, 2010, and to $30/tonne by July 1, 2012. As part of its involvement with the Western Climate Initiative, British Columbia has also announced that certain upstream oil and gas facilities will be included in a regional cap and trade system beginning in 2012. It is estimated that six facilities in British Columbia will be included under the cap and trade system, based on a proposed 25 kt CO_2e threshold. Saskatchewan is expected to release GHG regulations in 2010 that may require the North Tangleflags in-situ heavy oil facility to meet a reduction target for its GHG emissions intensity. In the UK, GHG regulations have been in effect since 2005. During Phase 1 (2005 – 2007) of the UK National Allocation Plan, the Company operated below its CO_2 allocation. For Phase 2 (2008 – 2012) the Company's CO_2 allocation has been decreased below the Company's estimated current operations emissions. 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.

Legislation to regulate GHGs in the United States through a cap and trade system is currently before the US Congress, although there is no certainty as to the form or stringency of the final legislation. In the absence of legislation, the US Environmental Protection Agency (EPA) is authorized under the Clean Air Act to regulate GHGs, although EPA action would be subject to legal and political challenges. The ultimate form of Canadian regulation is anticipated to be strongly influenced by the regulatory decisions made within the US. 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 facility emission threshold, 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 enhanced oil recovery, and participation in an industry initiative to promote an integrated CO_2 capture and storage network.

The additional requirements of enacted or proposed GHG regulations on the Company's operations will increase capital expenditures and operating expenses, especially those related to the Horizon Project and the Company's other existing and planned large oil sands projects. This may have an adverse effect on the Company's 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 have been developed that adopt a structured process to emission reductions that is commensurate with technological development and operational requirements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make judgments, assumptions and estimates in the application of Canadian GAAP that have a significant impact on the financial results of the Company. Actual results may differ from those estimates, and those differences may be material. Critical accounting estimates are reviewed by the Company's Audit Committee annually. The Company believes the following are the most critical accounting estimates in preparing its consolidated financial statements.

Property, Plant and Equipment / Depletion, Depreciation and Amortization

Under Canadian GAAP, the Company follows the CICA's guideline on the full cost method of accounting for its conventional crude oil and natural gas properties and equipment. Accordingly, all costs relating to the exploration for and development of conventional crude oil and natural gas reserves, whether successful or not, are capitalized and accumulated in country-by-country cost centres. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more. Under Canadian GAAP, substantially all of the capitalized costs and estimated future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country using estimated future prices and costs, rather than constant prices and costs as required by the SEC for US GAAP purposes.

Under Canadian GAAP, the carrying amount of crude oil and natural gas properties in each cost centre may not exceed their recoverable amount ("the ceiling test"). The recoverable amount is calculated as the undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, an impairment loss equal to the amount by which the carrying amount of the properties exceeds their estimated fair value is charged against net earnings. Fair value is calculated as the cash flow from those properties using proved and probable reserves and estimated future prices and costs, discounted at a risk-free interest rate. At December 31, 2009, a ceiling test impairment of $115 million was recognized under Canadian GAAP related to the Olowi Field in Offshore Gabon. Further, net revenues exceed capitalized costs for all other cost centres; therefore, no other impairments were required under Canadian GAAP. Under US GAAP, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices and costs using the average first-day-of-the-month price during the previous 12-month period and costs as at the balance sheet date and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. These differences in applying the ceiling test in the current year resulted in the recognition of an after-tax ceiling test impairment of $815 million under US GAAP.

The alternate acceptable method of accounting for crude oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method, cost centres are defined based on reserve pools rather than by country. The use of the full cost method usually results in higher capitalized costs and increased DD&A rates compared to the successful efforts method.

Crude Oil and Natural Gas Reserves

The estimation of reserves involves the exercise of judgment. Forecasts 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 and interpretations. The Company expects that over time its reserve estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production levels. 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 DD&A charge to net earnings. Downward revisions to reserve estimates may also result in an impairment of crude oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

Asset Retirement Obligations

Under CICA Handbook Section 3110, "Asset Retirement Obligations", the Company is required to recognize a liability for the future retirement obligations 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 fair values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the estimated fair value of the ARO are capitalized as part of the cost of associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's average credit-adjusted risk-free interest rate, which is currently 6.9%. In subsequent periods, the ARO is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. The estimates described impact earnings by way of depletion on the retirement cost and accretion on the asset retirement liability. 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.

An ARO is not recognized for assets with an indeterminate useful life (e.g. pipeline assets and the Horizon upgrader and related infrastructure) because an amount cannot be reasonably determined. An ARO for these assets will be recorded in the first period in which the lives of these assets are determinable.

Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences between the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted or enacted as of the consolidated balance sheet date. Accounting for income taxes is a complex process that requires management to interpret frequently changing laws and regulations (e.g. changing income tax rates) and make certain judgments with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. These interpretations and judgments impact the current and future income tax provisions, future income tax assets and liabilities, and net earnings.

Risk Management Activities

The Company utilizes various 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.

The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies. 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 has relied primarily on external readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction and these differences may be material.

Purchase Price Allocations

The purchase prices of business combinations and asset acquisitions 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 assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities. 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 DD&A 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 judgments 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 (a) crude oil and natural gas reserves, and (b) future prices of crude oil and natural gas. Reserve estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgments 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.

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, 2009, 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, 2009, 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 2009 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal controls 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.

NEW ACCOUNTING STANDARDS

During 2009, the Company adopted the following new accounting standards issued by the CICA:

Goodwill and Intangible Assets

- Effective January 1, 2009 Section 3064 – "Goodwill and Intangible Assets" replaced Section 3062 – "Goodwill and Other Intangible Assets" and Section 3450 – "Research and Development Costs". In addition, EIC-27 – "Revenue and Expenditures during the Pre-operating Period" was withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard, which was adopted retroactively, did not have an impact on the Company's results of operations or financial position.

Credit Risk and the Fair Value of Financial Assets and Liabilities

- On January 20, 2009 the Emerging Issues Committee ("EIC") issued a new abstract EIC–173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". This abstract concludes that an entity's own credit risk and the credit risk of the counterparty should be taken into account when determining the fair value of financial assets and financial liabilities, including derivative financial instruments. This abstract applies to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. The adoption of this abstract did not have a material impact on the Company's results of operations or financial position.

The Company also adopted the following amendments to accounting standards issued by the CICA:

Financial Instruments

- Effective July 1, 2009 Section 3855 – "Financial Instruments – Recognition and Measurement" was amended to add guidance on the assessment of embedded derivatives upon reclassification of a financial asset from the held-for-trading category. This amendment did not have any impact on the Company's results of operations or financial position.

Financial Instruments – Disclosures

- Effective October 1, 2009 Section 3862 – "Financial Instruments – Disclosures" was amended to include additional disclosure requirements for fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendment requires the classification and disclosure of fair value measurements using a three-level hierarchy that reflects the significance of the inputs used in making the fair value measurements. This amendment affected disclosure only and did not impact the Company's accounting for financial instruments.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable enterprises will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board ("IASB") in place of Canadian GAAP effective January 1, 2011.

The Company has established a formal IFRS project governance structure. The structure includes a Steering Committee, which consists of senior levels of management from finance and accounting, operations and information technology ("IT"). The Steering Committee provides regular updates to the Company's Management and the Audit Committee of the Board of Directors.

The Company's IFRS conversion project has been broken down into the following phases:

- Phase 1 Diagnostic – identification of potential accounting and reporting differences between Canadian GAAP and IFRS.
- Phase 2 Planning – establishment of project governance, processes, resources, budget and timeline.
- Phase 3 Policy Delivery and Documentation – establishment of accounting policies under IFRS.
- Phase 4 Policy Implementation – establishment of processes for accounting and reporting, IT change requirements, and education.
- Phase 5 Sustainment – ongoing compliance with IFRS after implementation.

The Company has completed the Diagnostic and Planning phases (Phases 1 and 2). Significant differences were identified in accounting for Property, Plant & Equipment ("PP&E"), including exploration costs, depletion and depreciation, capitalized interest, impairment testing, and asset retirement obligations. Other significant differences were noted in accounting for stock-based compensation, risk management activities, and income taxes. The Company is continuing to perform the necessary research to develop and document IFRS policies to address the major differences noted (Phase 3). A summary of the significant differences identified is included below. At this time, the impact on the Company's future financial position and results of operations is not reasonably determinable. In addition, certain IFRS standards are expected to change prior to adoption in 2011, and the impact of these potential changes is not known.

The Company has identified, developed and tested process and system changes required to capture data required for IFRS accounting and reporting (Phase 4), including requirements to capture both Canadian GAAP and IFRS data in 2010. IT system changes are substantially complete and implemented as at December 31, 2009.

Summary of Identified IFRS Accounting Policy Differences

Property, Plant & Equipment

Adoption of IFRS will significantly impact the Company's accounting policies for PP&E. For Canadian GAAP purposes, the Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16. Application of the full cost method of accounting is discussed in the "Critical Accounting Estimates" section of this MD&A. Significant differences in accounting for PP&E under IFRS include:

- Pre-exploration costs must be expensed. Under full cost accounting, these costs are currently included in the country cost centre.
- Exploration and evaluation costs will be initially capitalized as exploration and evaluation assets. Once technical feasibility and commercial viability of reserves is established for an area, the costs will be transferred to PP&E. If technically feasible and commercially viable reserves are not established for a new area, the costs must be expensed. Under full cost accounting, exploration and evaluation costs are currently disclosed as PP&E but withheld from depletion. Costs are transferred to the depletable assets when proved reserves are assigned or when it is determined that the costs are impaired.
- PP&E for producing properties will be depreciated at an asset level. Under full cost accounting, PP&E is depleted on a country cost centre basis.
- Interest directly attributable to the acquisition or construction of a qualifying asset must be capitalized to the cost of the asset. Under Canadian GAAP, capitalization of interest is discretionary.
- Impairment of PP&E will be tested at a cash generating unit level (the lowest level at which cash inflows can be identified). Under full cost accounting, impairment is tested at the country cost centre level.

IFRS 1 "First-time Adoption of International Financial Reporting Standards" issued by the IASB includes a transition exemption for oil and gas companies following full cost accounting under their previous GAAP. The transition exemption allows full cost companies to allocate their existing full cost PP&E balances using reserve values or volumes to IFRS compliant units of account without requiring retroactive adjustment, subject to an initial impairment test. The Company intends to adopt this transition exemption.

Asset Retirement Obligations

Canadian GAAP accounting requirements for ARO are discussed in the "Critical Accounting Estimates" section of this MD&A. A significant difference in accounting for ARO under IFRS is that the liability must be re-measured at each balance sheet date using the current discount rates, whereas under Canadian GAAP the discount rates do not change once the liability is recorded. On transition to IFRS, the change in ARO liability on PP&E for which the full cost exemption above is applied must be recorded in retained earnings. For the change in ARO liability on other non-full cost PP&E, the change will be adjusted to PP&E in accordance with the general exemption for decommissioning liabilities included in IFRS 1. In future periods, the impact of changes in discount rates on the ARO liability for all PP&E is adjusted to PP&E.

Stock-based Compensation

Under Canadian GAAP, the Company's stock option plan liability is valued using the intrinsic value method, calculated as the amount by which the market price of the Company's shares exceeds the exercise price of the option for vested options. Under IFRS, the stock option plan liability must be measured using a fair value option pricing model such as the Black-Scholes-Merton model. The Company intends to utilize the exemption in IFRS 1 under which options that were settled prior to January 1, 2010 will not have to be retrospectively restated.

Income Taxes

Both Canadian GAAP and IFRS follow the liability method of accounting for income taxes, where tax liabilities and assets are recognized on temporary differences. However, there are certain exceptions to the treatment of temporary differences under IFRS that may result in an adjustment to the Company's future tax liability under IFRS. In addition, the Company's future tax liability will be impacted by the tax effects of any changes noted in the above areas.

Other IFRS 1 Exemptions

The Company also intends to adopt the following IFRS 1 transition exemptions:

- The Company intends to elect to reset the foreign currency translation adjustment to zero by transferring the Canadian GAAP balance to retained earnings on January 1, 2010, rather than retrospectively restating the balance.
- The Company intends to adopt the IFRS 1 election to not restate business combinations entered into prior to January 1, 2010.

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. The Company expects production levels in 2010 to average between 400,000 bbl/d and 445,000 bbl/d of crude oil and NGLs and between 1,117 mmcf/d and 1,185 mmcf/d of natural gas.

The forecasted capital expenditures in 2010 are currently expected to be as follows:

($ millions)	2010 Forecast
Conventional crude oil and natural gas	
North America natural gas	$ 674
North America crude oil and NGLs	1,900
North Sea	199
Offshore West Africa	264
Property acquisitions, dispositions and midstream	100
	$ 3,137
Oils Sands Mining and Upgrading	
Horizon Phase 2/3 – Tranche 2	$ 479
Horizon Phase 2/3 – Engineering	95
Sustaining capital	164
Capitalized interest and other costs	47
	$ 785
Total	$ 3,922

The above capital expenditure budget incorporates the following levels of drilling activity:

(Number of wells)	2010 Forecast
Targeting natural gas	93
Targeting crude oil	966
Stratigraphic test / service wells – conventional	227
Stratigraphic test wells – mining	166
Total	1,452

North America Natural Gas

The 2010 North America natural gas drilling program is highlighted by the continued high-grading of the Company's natural gas asset base as follows:

(Number of wells)	2010 Forecast
Coal bed methane and shallow natural gas	8
Conventional natural gas	36
Cardium natural gas	1
Deep natural gas	47
Foothills natural gas	1
Total	93

North America Crude Oil and NGLs

The 2010 North America crude oil drilling program is highlighted by continued development of the Primrose thermal projects, Pelican Lake, and a strong conventional primary heavy program, as follows:

(Number of wells)	2010 Forecast
Conventional primary heavy crude oil	610
Thermal heavy crude oil	28
Light crude oil	117
Pelican Lake crude oil	201
Total	956

Oil Sands Mining and Upgrading

In 2010, Horizon Phase 2/3 Tranche 2 expenditures are targeted to increase reliability of the plant while also affording some debottlenecking opportunities.

Engineering and procurement is under way for Tranche 2 of the Phase 2/3 expansion, and Tranches 3 and 4 of Phase 2/3 continue to be re-profiled. The Company continues to work on completing its lessons learned from the construction of Phase 1 and implementing these into the development of future expansions.

North Sea

During 2010, the Company will recommence platform drilling activities in the Northern North Sea with a program of infill wells and workovers.

Offshore West Africa

During 2010, the Company will complete the project to increase capacity on the Espoir FPSO. At Olowi, the Company will complete commissioning of the remaining platforms and continue the drilling program from these locations.

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 2009, excluding mark-to-market gains (losses) on risk management activities and capitalized interest, 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	$ 109	$ 0.20	$ 90	$ 0.17
Including financial derivatives	$ 91	$ 0.17	$ 76	$ 0.14
Natural gas – AECO C$0.10/mcf [1]				
Excluding financial derivatives	$ 33	$ 0.06	$ 24	$ 0.04
Including financial derivatives	$ 18	$ 0.03	$ 14	$ 0.03
Volume changes				
Crude oil – 10,000 bbl/d	$ 161	$ 0.30	$ 105	$ 0.19
Natural gas – 10 mmcf/d	$ 12	$ 0.02	$ 4	$ 0.01
Foreign currency rate change				
$0.01 change in US$ [1]				
Including financial derivatives	$ 95 – 97	$ 0.17 – 0.18	$ 31 – 32	$ 0.06
Interest rate change – 1%	$ 13	$ 0.02	$ 13	$ 0.02

(1) For details of financial instruments in place, refer to note 13 to the Company's audited annual consolidated financial statements as at December 31, 2009.

DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2009	2008	2007
Crude oil and NGLs (bbl/d)							
North America – Conventional	**253,833**	**232,139**	**223,307**	**229,206**	**234,523**	243,826	246,779
North America – Oil Sands Mining and Upgrading	**3,384**	**59,599**	**66,907**	**70,194**	**50,250**	–	–
North Sea	**42,369**	**40,362**	**34,034**	**34,408**	**37,761**	45,274	55,933
Offshore West Africa	**30,431**	**33,572**	**35,021**	**32,643**	**32,929**	26,567	28,520
Total	**330,017**	**365,672**	**359,269**	**366,451**	**355,463**	315,667	331,232
Natural gas (mmcf/d)							
North America	**1,347**	**1,322**	**1,264**	**1,218**	**1,287**	1,472	1,643
North Sea	**10**	**10**	**8**	**12**	**10**	10	13
Offshore West Africa	**12**	**20**	**21**	**20**	**18**	13	12
Total	**1,369**	**1,352**	**1,293**	**1,250**	**1,315**	1,495	1,668
Barrels of oil equivalent (boe/d)							
North America – Conventional	**478,301**	**452,494**	**433,928**	**432,167**	**449,054**	489,081	520,564
North America – Oil Sands Mining and Upgrading	**3,384**	**59,599**	**66,907**	**70,194**	**50,250**	–	–
North Sea	**44,039**	**42,045**	**35,380**	**36,440**	**39,444**	46,956	58,099
Offshore West Africa	**32,418**	**36,846**	**38,540**	**36,056**	**35,982**	28,808	30,543
Total	**558,142**	**590,984**	**574,755**	**574,857**	**574,730**	564,845	609,206

PER UNIT RESULTS – CONVENTIONAL (1)

	Q1	Q2	Q3	Q4	2009	2008	2007
Crude oil and NGLs ($/bbl)							
Sales price (2)	**$ 41.25**	**$ 59.56**	**$ 62.90**	**$ 68.00**	**$ 57.68**	$ 82.41	$ 55.45
Royalties	**3.98**	**7.27**	**7.89**	**7.96**	**6.73**	10.48	5.94
Production expense	**15.02**	**16.59**	**16.71**	**15.45**	**15.92**	16.26	13.34
Netback	**$ 22.25**	**$ 35.70**	**$ 38.30**	**$ 44.59**	**$ 35.03**	$ 55.67	$ 36.17
Natural gas ($/mcf)							
Sales price (2)	**$ 5.46**	**$ 4.11**	**$ 3.80**	**$ 4.75**	**$ 4.53**	$ 8.39	$ 6.85
Royalties (3)	**0.72**	**0.06**	**0.13**	**0.35**	**0.32**	1.46	1.11
Production expense	**1.18**	**1.05**	**1.05**	**1.03**	**1.08**	1.02	0.91
Netback	**$ 3.56**	**$ 3.00**	**$ 2.62**	**$ 3.37**	**$ 3.13**	$ 5.91	$ 4.83
Barrels of oil equivalent ($/boe)							
Sales price (2)	**$ 37.87**	**$ 44.52**	**$ 45.52**	**$ 51.95**	**$ 44.87**	$ 68.62	$ 49.05
Royalties	**4.14**	**4.34**	**4.85**	**5.60**	**4.72**	9.78	6.26
Production expense	**11.77**	**12.21**	**12.26**	**11.72**	**11.98**	11.79	9.75
Netback	**$ 21.96**	**$ 27.97**	**$ 28.41**	**$ 34.63**	**$ 28.17**	$ 47.05	$ 33.04

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Net of transportation and blending costs and excluding risk management activities.
(3) Natural gas royalties for 2009 reflect the impact of natural gas physical sales contracts.

TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2009	2008
TSX – C$						
Trading volume (thousands)					**520,160**	679,738
Share Price ($/share)						
High	**$ 57.20**	**$ 68.69**	**$ 76.91**	**$ 79.00**	**$ 79.00**	$ 111.30
Low	**$ 35.85**	**$ 47.70**	**$ 52.71**	**$ 65.97**	**$ 35.85**	$ 34.19
Close	**$ 48.91**	**$ 61.19**	**$ 72.30**	**$ 76.00**	**$ 76.00**	$ 48.75
Market capitalization as at December 31 ($ millions)					**$ 41,217**	$ 26,373
Shares outstanding (thousands)					**542,327**	540,991
NYSE – US$						
Trading volume (thousands)					**757,307**	967,228
Share Price ($/share)						
High	**$ 48.54**	**$ 63.46**	**$ 71.93**	**$ 76.51**	**$ 76.51**	$ 109.32
Low	**$ 27.69**	**$ 37.73**	**$ 45.03**	**$ 62.05**	**$ 27.69**	$ 26.43
Close	**$ 38.56**	**$ 52.49**	**$ 67.19**	**$ 71.95**	**$ 71.95**	$ 39.98
Market capitalization as at December 31($ millions)					**$ 39,020**	$ 21,629
Shares outstanding (thousands)					**542,327**	540,991

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 Canadian generally accepted accounting principles 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 December 31, 2009; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2009.

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

Douglas A. Proll, CA
CHIEF FINANCIAL OFFICER &
SENIOR VICE-PRESIDENT, FINANCE

Randall S. Davis, CA
VICE-PRESIDENT, FINANCE &
ACCOUNTING

Calgary, Alberta, Canada
March 3, 2010

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 15(d)–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 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, 2009. 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, 2009, as stated in their Auditors' Report.

Steve W. Laut
PRESIDENT

Douglas A. Proll, CA
CHIEF FINANCIAL OFFICER &
SENIOR VICE-PRESIDENT, FINANCE

Calgary, Alberta, Canada
March 3, 2010

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Canadian Natural Resources Limited

We have completed integrated audits of Canadian Natural Resources Limited's 2009, 2008 and 2007 consolidated financial statements and of its internal control over financial reporting as at December 31, 2009. Our opinions, based on our audits, are presented below.

Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited (the "Company") as at December 31, 2009 and December 31, 2008, and the related consolidated statements of earnings, shareholders' equity, comprehensive income and cash flows for each of the years in the three year period ended December 31, 2009. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits of the Company's financial statements as at December 31, 2009 and for each of the years in the three year period then ended in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. A financial statement audit also includes assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as at December 31, 2009 and December 31, 2008 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2009 in accordance with Canadian generally accepted accounting principles.

Internal Control Over Financial Reporting

We have also audited Canadian Natural Resources Limited's internal control over financial reporting as at December 31, 2009, based on criteria established in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's 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. 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 opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as at December 31, 2009 based on criteria established in Internal Control – Integrated Framework issued by the COSO.

PricewaterhouseCoopers LLP

Chartered Accountants
March 3, 2010

CONSOLIDATED BALANCE SHEETS

As at December 31 (millions of Canadian dollars)	2009	2008
ASSETS		
Current assets		
Cash and cash equivalents	$ 13	$ 27
Accounts receivable	1,148	1,059
Inventory, prepaids and other	584	455
Future income tax (note 8)	146	–
Current portion of other long-term assets (note 3)	–	1,851
	1,891	3,392
Property, plant and equipment (note 4)	39,115	38,966
Other long-term assets (note 3)	18	292
	$ 41,024	$ 42,650
LIABILITIES		
Current liabilities		
Accounts payable	$ 240	$ 383
Accrued liabilities	1,522	1,802
Future income tax (note 8)	–	585
Current portion of long-term debt (note 5)	–	420
Current portion of other long-term liabilities (note 6)	643	230
	2,405	3,420
Long-term debt (note 5)	9,658	12,596
Other long-term liabilities (note 6)	1,848	1,124
Future income tax (note 8)	7,687	7,136
	21,598	24,276
SHAREHOLDERS' EQUITY		
Share capital (note 9)	2,834	2,768
Retained earnings	16,696	15,344
Accumulated other comprehensive (loss) income (note 10)	(104)	262
	19,426	18,374
	$ 41,024	$ 42,650

Commitments and contingencies (note 14)

Approved by the Board of Directors:

Catherine M Best

Catherine M. Best
CHAIR OF THE AUDIT COMMITTEE
AND DIRECTOR

N. Murray Edwards
VICE-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)	2009	2008	2007
Revenue	**$ 11,078**	$ 16,173	$ 12,543
Less: royalties	**(936)**	(2,017)	(1,391)
Revenue, net of royalties	**10,142**	14,156	11,152
Expenses			
Production	**2,987**	2,451	2,184
Transportation and blending	**1,218**	1,936	1,570
Depletion, depreciation and amortization	**2,819**	2,683	2,863
Asset retirement obligation accretion (note 6)	**90**	71	70
Administration	**181**	180	208
Stock-based compensation expense (recovery) (note 6)	**355**	(52)	193
Interest, net	**410**	128	276
Risk management activities (note 13)	**738**	(1,230)	1,562
Foreign exchange (gain) loss	**(631)**	718	(471)
	8,167	6,885	8,455
Earnings before taxes	**1,975**	7,271	2,697
Taxes other than income tax (note 8)	**106**	178	165
Current income tax expense (note 8)	**388**	501	380
Future income tax (recovery) expense (note 8)	**(99)**	1,607	(456)
Net earnings	**$ 1,580**	$ 4,985	$ 2,608
Net earnings per common share (note 12)			
Basic and diluted	**$ 2.92**	$ 9.22	$ 4.84

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

For the years ended December 31 (millions of Canadian dollars)	2009	2008	2007
Share capital (note 9)			
Balance – beginning of year	**$ 2,768**	$ 2,674	$ 2,562
Issued upon exercise of stock options	**24**	18	21
Previously recognized liability on stock options exercised for common shares	**42**	76	91
Balance – end of year	**2,834**	2,768	2,674
Retained earnings			
Balance – beginning of year, as originally reported	**15,344**	10,575	8,141
Transition adjustment on adoption of financial instruments standards	**–**	–	10
Balance – beginning of year, as restated	**15,344**	10,575	8,151
Net earnings	**1,580**	4,985	2,608
Dividends on common shares (note 9)	**(228)**	(216)	(184)
Balance – end of year	**16,696**	15,344	10,575
Accumulated other comprehensive (loss) income (note 10)			
Balance – beginning of year, as originally reported	**262**	72	(13)
Transition adjustment on adoption of financial instruments standards	**–**	–	159
Balance – beginning of year, as restated	**262**	72	146
Other comprehensive (loss) income, net of taxes	**(366)**	190	(74)
Balance – end of year	**(104)**	262	72
Shareholders' equity	**$ 19,426**	$ 18,374	$ 13,321

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (millions of Canadian dollars)	2009	2008	2007
Net earnings	**$ 1,580**	$ 4,985	$ 2,608
Net change in derivative financial instruments designated as cash flow hedges			
Unrealized (loss) income during the year, net of taxes of $5 million (2008 – $1 million, 2007 – $6 million)	**(33)**	30	38
Reclassification to net earnings, net of taxes of $1 million (2008 – $6 million, 2007 – $45 million)	**(10)**	(12)	(96)
	(43)	18	(58)
Foreign currency translation adjustment			
Translation of net investment	**(323)**	172	(16)
Other comprehensive (loss) income, net of taxes	**(366)**	190	(74)
Comprehensive income	**$ 1,214**	$ 5,175	$ 2,534

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31 (millions of Canadian dollars)	2009	2008	2007
Operating activities			
Net earnings	**$ 1,580**	$ 4,985	$ 2,608
Non-cash items			
Depletion, depreciation and amortization	**2,819**	2,683	2,863
Asset retirement obligation accretion	**90**	71	70
Stock-based compensation expense (recovery)	**355**	(52)	193
Unrealized risk management loss (gain)	**1,991**	(3,090)	1,400
Unrealized foreign exchange (gain) loss	**(661)**	832	(524)
Deferred petroleum revenue tax expense (recovery)	**15**	(67)	44
Future income tax (recovery) expense	**(99)**	1,607	(456)
Other	**5**	25	38
Abandonment expenditures	**(48)**	(38)	(71)
Net change in non-cash working capital (note 15)	**(235)**	(189)	(346)
	5,812	6,767	5,819
Financing activities			
Repayment of bank credit facilities, net	**(2,021)**	(623)	(1,925)
Issue of medium-term notes	**–**	–	273
Repayment of senior unsecured notes	**(34)**	(31)	(33)
Issue of US dollar debt securities	**–**	1,215	2,553
Issue of common shares on exercise of stock options	**24**	18	21
Dividends on common shares	**(225)**	(208)	(178)
Net change in non-cash working capital (note 15)	**(12)**	46	8
	(2,268)	417	719
Investing activities			
Expenditures on property, plant and equipment	**(2,985)**	(7,433)	(6,464)
Net proceeds on sale of property, plant and equipment	**36**	20	110
Net expenditures on property, plant and equipment	**(2,949)**	(7,413)	(6,354)
Net change in non-cash working capital (note 15)	**(609)**	235	(186)
	(3,558)	(7,178)	(6,540)
(Decrease) increase in cash and cash equivalents	**(14)**	6	(2)
Cash and cash equivalents – beginning of year	**27**	21	23
Cash and cash equivalents – end of year	**$ 13**	$ 27	$ 21

Supplemental disclosure of cash flow information (note 15)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(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 head-quartered in Calgary, Alberta, Canada. The Company's conventional crude oil and natural gas operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire and Gabon in Offshore West Africa.

Horizon oil sands properties ("Horizon") produce synthetic crude oil through bitumen mining and upgrading operations. During 2009, Horizon Phase 1 assets were completed and available for their intended use. All Horizon related financial results are included in the "Oil Sands Mining and Upgrading" segment.

Also within Western Canada, the Company maintains certain midstream activities that include pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US GAAP") is contained in note 17.

Significant accounting policies are summarized as follows:

(A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and partnerships. A significant portion of the Company's activities are conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

(B) MEASUREMENT UNCERTAINTY

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts.

Purchase price allocations, depletion, depreciation and amortization, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. The estimation of reserves involves the exercise of judgement. Forecasts 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 and interpretations. 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. As a result, the impact of differences between actual and estimated oil and gas reserves amounts on the consolidated financial statements of future periods may be material.

The calculation of asset retirement obligations includes estimates of the future costs to settle the asset retirement obligation, the timing of the cash flows to settle the obligation, and the future inflation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods may be material.

The calculation of income taxes requires judgement in applying tax laws and regulations, estimating the timing of temporary difference reversals, and estimating the realizability of future tax assets. These estimates impact current and future income tax assets and liabilities, and current and future income tax expense (recovery).

The measurement of petroleum revenue tax expense in the United Kingdom and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of crude oil and natural gas reserves, commodity prices and the timing of future events, which may result in material changes to deferred amounts.

The estimation of fair value for derivative financial instruments requires the use of assumptions. In determining these assumptions, the Company has relied primarily on external, readily observable market inputs including quoted commodity prices and volatility, interest rate yield curves, and foreign exchange rates. 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.

(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 on the balance sheet.

(D) INVENTORIES

Inventories are carried at the lower of cost and net realizable value. Cost consists of purchase costs, direct production costs, direct overhead and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Inventories are primarily comprised of crude oil production held for sale.

(E) PROPERTY, PLANT AND EQUIPMENT

Conventional Crude Oil and Natural Gas

The Company follows the full cost method of accounting for its conventional crude oil and natural gas properties and equipment as prescribed by Accounting Guideline 16 ("AcG 16") issued by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of conventional crude oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Directly attributable administrative overhead incurred during the development of certain large capital projects is capitalized until the projects are available for their intended use. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of a gain or loss except where such dispositions result in a change in the depletion rate of the specific cost centre of 20% or more.

Oil Sands Mining and Upgrading

Horizon is comprised of both mining and upgrading operations and accordingly, capitalized costs are accounted for separately from the Company's Canadian conventional crude oil and natural gas costs. Capitalized mining activity costs include property acquisition, construction and development costs. Construction and development costs are capitalized separately to each Phase of Horizon. The construction and development of a particular Phase of Horizon is considered complete once the Phase is available for its intended use. Costs related to major maintenance turnaround activities are capitalized and amortized on a straight-line basis over the period to the next scheduled major maintenance turnaround. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest and stock-based compensation, and all directly attributable Phase 1 administrative costs ceased and depletion, depreciation and amortization of these assets commenced.

Midstream and Other

The Company capitalizes all costs that expand the capacity or extend the useful life of the assets.

(F) OVERBURDEN REMOVAL COSTS

Overburden removal costs incurred during development of the Horizon mine are capitalized to property, plant and equipment. Overburden removal costs incurred during production of the Horizon mine are included in the cost of inventory, unless the overburden removal activity has resulted in a betterment of the mineral property, in which case the costs are capitalized to property, plant and equipment. Capitalized overburden removal costs are amortized over the life of the mining reserves that directly benefit from the overburden removal activity.

(G) CAPITALIZED INTEREST

The Company capitalizes construction period interest based on major qualifying costs incurred and the Company's cost of borrowing. Interest capitalization on a particular project ceases once this project is available for its intended use.

(H) LEASES

Leases that transfer substantially all of the benefits and risks of ownership to the Company are accounted for as capital leases and are recorded as property, plant and equipment with an offsetting liability. All other leases are accounted for as operating leases whereby lease costs are expensed as incurred. Contractual arrangements that meet the definition of a lease are accounted for as capital leases or operating leases as appropriate.

(I) DEPLETION, DEPRECIATION, AMORTIZATION AND IMPAIRMENT

Conventional Crude Oil and Natural Gas

Substantially all costs related to each country-by-country cost centre are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties and major development projects. Costs for major development projects, as identified by management, are not subject to depletion until the projects are available for their intended use. Unproved properties and major development projects are assessed periodically to determine whether impairment has occurred. When proved reserves are assigned or the value of an unproved property or major development project is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion. Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its conventional crude oil and natural gas properties ("the properties") relative to their recoverable amount ("the ceiling test") for each cost centre at each annual balance sheet date, or more frequently if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, an impairment loss is recognized in depletion and depreciation expense equal to the amount by which the carrying amount of the properties exceeds their fair value. Fair value is calculated as the cash flow from those properties using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

Oil Sands Mining and Upgrading

Mine-related costs and costs of the upgrader and related infrastructure located on the Horizon site are amortized on the unit-of-production method based on the estimated proved reserves of Horizon or productive capacity, respectively. Moveable mine-related equipment is depreciated on a straight-line basis over its estimated useful life.

The Company reviews the carrying amount of Horizon relative to its recoverable amount if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from Horizon assets using proved and probable reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, an impairment loss is recognized in depletion equal to the amount by which the carrying amount of the assets exceeds fair value. Fair value is calculated as the discounted cash flow from Horizon using proved and probable reserves and expected future prices and costs.

Midstream and Other

Midstream assets are depreciated on a straight-line basis over their estimated lives. The Company reviews the recoverability of the carrying amount of the midstream assets when events or circumstances indicate that the carrying amount might not be recoverable. If the carrying amount of the midstream assets exceeds their recoverable amount, an impairment loss equal to the amount by which the carrying amount of the midstream assets exceeds their fair value is recognized in depreciation. Other capital assets are amortized on a declining balance basis.

(J) ASSET RETIREMENT OBLIGATIONS

The Company provides for future asset retirement obligations on its resource properties, facilities, production platforms, gathering systems, and oil sands mining operations and tailings ponds based on current legislation and industry operating practices. The fair values of asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Retirement costs equal to the fair value of the asset retirement obligations are capitalized as part of the cost of the associated property, plant and equipment and are amortized to expense through depletion and depreciation over the lives of the respective assets. The fair value of an asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company's average credit-adjusted risk-free interest rate. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for changes in the amount or timing of the underlying future cash flows. Actual expenditures are charged against the accumulated asset retirement obligation as incurred.

The Company's Horizon upgrader and related infrastructure and its midstream pipelines have an indeterminate life and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligations for these assets will be recorded in the year in which the lives of the assets are determinable.

(K) FOREIGN CURRENCY TRANSLATION

Foreign operations that are self-sustaining are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in accumulated other comprehensive income (loss) in shareholders' equity in the consolidated balance sheets.

Foreign operations that are integrated are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date. Non-monetary assets and liabilities are translated at the exchange rate in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related assets. Gains or losses on translation of integrated foreign operations and foreign currency balances are included in the consolidated statements of earnings.

(L) REVENUE RECOGNITION AND COSTS OF GOODS SOLD

Revenue from the production 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 as reported represents the Company's share and is presented before royalty payments to governments and other mineral interest owners. Revenue, net of royalties represents the Company's share after 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.

(M) PRODUCTION SHARING CONTRACTS

Production generated from Offshore West Africa is currently shared under the terms of various Production Sharing Contracts ("PSCs"). Revenues 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 PSCs.

(N) PETROLEUM REVENUE TAX

The Company accounts for the UK petroleum revenue tax ("PRT") over the life of the field. The total future liability or recovery of PRT is estimated using proved and probable reserves and anticipated future sales prices and costs. The estimated future PRT is then apportioned to accounting periods on the basis of total estimated future operating income. Changes in the estimated total future PRT are accounted for prospectively.

(O) INCOME TAX

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated 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 or enacted as of the consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

Taxable income arising from the conventional crude oil and natural gas business in Canada is primarily generated through partnerships, with the related income taxes payable in subsequent periods. Accordingly, North America current and future income taxes have been provided on the basis of this corporate structure.

(P) STOCK-BASED COMPENSATION PLANS

The Company accounts for stock-based compensation using the intrinsic value method as the Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. A liability for potential cash settlements under the Option Plan is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares, after consideration of an estimated forfeiture rate. This liability is revalued at each reporting date to reflect changes in the market price of the Company's common shares and actual forfeitures, with the net change recognized in net earnings, or capitalized during the construction period in the case of Horizon. 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 employees and any previously recognized liability associated with the stock options are recorded as share capital.

The Company has an employee stock savings plan and a stock bonus plan. Contributions to the employee stock savings plan are recorded as compensation expense at the time of the contribution. Contributions to the stock bonus plan are recognized as compensation expense over the related vesting period.

(Q) FINANCIAL INSTRUMENTS

The Company classifies its financial instruments into one of the following categories: held-for-trading financial assets and financial liabilities; held-to-maturity investments; loans and receivables; available-for-sale financial assets; and other financial liabilities. All financial instruments are required to be measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Held-for-trading financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. Available-for-sale financial assets are subsequently measured at fair value with changes in fair value recognized in other comprehensive income, net of tax. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents are classified as held-for-trading and are measured at fair value. Accounts receivable are classified as loans and receivables. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as other financial liabilities. Although the Company does not intend to trade its derivative financial instruments, risk management assets and liabilities are classified as held-for-trading for accounting purposes.

Financial assets and liabilities are 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 that are directly attributable to the acquisition or issue of a financial asset or liability and original issue discounts on long-term debt have been included in the carrying value of the related financial asset or liability and are amortized to consolidated net earnings over the life of the financial instrument using the effective interest method.

(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 on the consolidated balance sheet at estimated fair value at each balance sheet date. The estimated fair value of derivative financial instruments is 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 and discount rates.

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 of crude oil and natural gas production in order to protect cash flow for 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 consolidated net earnings in the same period or periods in which the commodity is sold. The ineffective portion of changes in the fair value of these designated contracts is immediately recognized in risk management activities in consolidated 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 consolidated net earnings.

The Company 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 included in interest expense in consolidated net earnings. Changes in the fair value of non-designated interest rate swap contracts are included in risk management activities in consolidated 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 are included in foreign exchange in consolidated 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 included in other comprehensive income and is reclassified to interest expense when realized, with the ineffective portion recognized in risk management activities in consolidated net earnings. Changes in the fair value of non-designated cross currency swap contracts are included in risk management activities in consolidated 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 on the consolidated balance sheets and amortized into consolidated net earnings in the period in which the underlying hedged item is 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 immediately in consolidated net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in consolidated net earnings immediately.

Upon termination of an interest rate swap designated as a fair value hedge, the interest rate swap is de-recognized on the balance sheet and the related long-term debt hedged is no longer revalued for 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 debt.

Foreign currency forward contracts are periodically used to manage foreign currency cash management 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 loss (gain) when realized. Changes in the fair value of foreign currency forward contracts not included as hedges are included in risk management activities in consolidated 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 on the net investment in self-sustaining foreign operations. Other comprehensive income is shown net of related income taxes.

(T) PER COMMON SHARE AMOUNTS

The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options not accounted for as a liability are used to purchase common shares at the average market price during the year. The Company's Option Plan described in note 9 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in the calculation of diluted earnings per share. The dilutive effect of other convertible securities is calculated by applying the "if-converted" method, which assumes that the securities are converted at the beginning of the period and that income items are adjusted to net earnings.

(U) RECENTLY ISSUED ACCOUNTING STANDARDS UNDER CANADIAN GAAP

The following standards will be effective for the Company's year beginning on January 1, 2011:

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

- Section 1582 – "Business Combinations", 1601 – "Consolidated Financial Statements", and 1602 – "Non-Controlling Interests" replace Section 1581 – "Business Combinations", and 1600 – "Consolidated Financial Statements". The new standards are the Canadian equivalent of IFRS 3 "Business Combinations" and IAS 27 "Consolidated and Separate Financial Statements". Section 1582 is effective for business combinations for acquisition dates on or after January 1, 2011. Earlier adoption is permitted, provided all three new standards are adopted simultaneously. Section 1582 requires equity instruments issued as part of the purchase consideration to be measured at fair value at the acquisition date, rather than the date when the acquisition was agreed to and announced. In addition, most acquisition costs are expensed as incurred, instead of being included in the purchase consideration. The new standard also requires non-controlling interests to be measured at fair value instead of carrying amounts. Section 1602 provides guidance on the treatment of non-controlling interests after acquisition. Section 1601 carries forward existing guidance on the preparation of consolidated financial statements, other than non-controlling interests. There is no impact on the Company's results of operations or financial position at this time.

(V) INTERNATIONAL FINANCIAL REPORTING STANDARDS

In February 2008, the CICA's Accounting Standards Board confirmed that Canadian publicly accountable entities will be required to adopt International Financial Reporting Standards ("IFRS") as promulgated by the International Accounting Standards Board in place of Canadian GAAP effective January 1, 2011. The Company has assessed which accounting policies will be affected by the change to IFRS and continues to assess the potential impact of these changes on its financial position and results of operations.

(W) COMPARATIVE FIGURES

Certain prior year figures have been reclassified to conform to the presentation adopted in 2009.

2. CHANGES IN ACCOUNTING POLICIES

During 2009, the Company adopted the following new accounting standards issued by the CICA:

Goodwill and Intangible Assets

- Effective January 1, 2009 Section 3064 – "Goodwill and Intangible Assets" replaced Section 3062 – "Goodwill and Other Intangible Assets" and Section 3450 – "Research and Development Costs". In addition, EIC-27 – "Revenue and Expenditures during the Pre-Operating Period" was withdrawn. The new standard addresses when an internally generated intangible asset meets the definition of an asset. The adoption of this standard, which was adopted retroactively, did not have an impact on the Company's results of operations or financial position.

Credit Risk and the Fair Value of Financial Assets and Liabilities

- On January 20, 2009 the Emerging Issues Committee ("EIC") issued a new abstract EIC–173 "Credit Risk and the Fair Value of Financial Assets and Financial Liabilities". This abstract concludes that an entity's own credit risk and the credit risk of the counterparty should be taken into account when determining the fair value of financial assets and financial liabilities, including derivative financial instruments. This abstract applies to all financial assets and liabilities measured at fair value in interim and annual financial statements for periods ending on or after January 20, 2009. The adoption of this abstract did not have a material impact on the Company's results of operations or financial position.

The Company also adopted the following amendments to accounting standards issued by the CICA:

Financial Instruments

- Effective July 1, 2009 Section 3855 – "Financial Instruments – Recognition and Measurement" was amended to add guidance on the assessment of embedded derivatives upon reclassification of a financial asset from the held-for-trading category. This amendment did not have any impact on the Company's results of operations or financial position.

Financial Instruments – Disclosures

- Effective October 1, 2009 Section 3862 – "Financial Instruments – Disclosures" was amended to include additional disclosure requirements for fair value measurements of financial instruments and to enhance liquidity risk disclosure requirements. The amendment requires the classification and disclosure of fair value measurements using a three-level hierarchy that reflects the significance of the inputs used in making the fair value measurements. This amendment affected disclosure only and did not impact the Company's accounting for financial instruments (note 13).

3. OTHER LONG-TERM ASSETS

	2009	2008
Risk management (note 13)	$ –	$ 2,119
Other	18	24
	18	2,143
Less: current portion	–	1,851
	$ 18	$ 292

4. PROPERTY, PLANT AND EQUIPMENT

	2009 Cost	2009 Accumulated depletion and depreciation	2009 Net	2008 Cost	2008 Accumulated depletion and depreciation	2008 Net
Conventional crude oil and natural gas						
North America	$ 38,259	$ 16,425	$ 21,834	$ 36,532	$ 14,381	$ 22,151
North Sea	3,879	2,067	1,812	4,167	2,119	2,048
Offshore West Africa	2,861	978	1,883	2,671	777	1,894
Other	42	14	28	40	14	26
Oil Sands Mining and Upgrading	13,481	186	13,295	12,573	–	12,573
Midstream	284	81	203	278	72	206
Head office	200	140	60	190	122	68
	$ 59,006	$ 19,891	$ 39,115	$ 56,451	$ 17,485	$ 38,966

During the year ended December 31, 2009, the Company capitalized directly attributable administrative costs of $41 million (2008 – $55 million; 2007 – $47 million) in the North Sea and Offshore West Africa, related to exploration and development and $79 million (2008 – $404 million; 2007 – $312 million) in North America, related to Oil Sands Mining and Upgrading.

During the year ended December 31, 2009, the Company capitalized $106 million (2008 – $481 million; 2007 – $356 million) in construction period interest costs related to Oil Sands Mining and Upgrading.

Included in property, plant and equipment are unproved land and major development projects that are not currently subject to depletion or depreciation:

	2009	2008
Conventional crude oil and natural gas		
North America	$ 2,102	$ 2,271
North Sea	4	12
Offshore West Africa	666	595
Other	28	26
Oil Sands Mining and Upgrading	752	12,573
	$ 3,552	$ 15,477

The Company has used the following estimated benchmark future prices ("escalated pricing") in its full cost ceiling tests for conventional crude oil and natural gas activities prepared in accordance with Canadian GAAP, as at December 31, 2009:

	2010	2011	2012	2013	2014	Average annual increase thereafter
Crude oil and NGLs						
North America						
WTI at Cushing (US$/bbl)	$ 79.17	$ 84.46	$ 86.89	$ 90.20	$ 92.01	2%
Western Canada Select (C$/bbl)	$ 74.14	$ 78.29	$ 76.86	$ 78.87	$ 79.49	2%
Edmonton Par (C$/bbl)	$ 84.25	$ 89.99	$ 92.61	$ 96.19	$ 98.13	2%
North Sea and Offshore West Africa						
North Sea Brent (US$/bbl)	$ 77.92	$ 83.19	$ 85.59	$ 88.88	$ 90.65	2%
Natural gas						
North America						
Henry Hub Louisiana (US$/mmbtu)	$ 5.70	$ 6.48	$ 6.70	$ 7.43	$ 8.12	2%
AECO (C$/mmbtu)	$ 5.36	$ 6.21	$ 6.44	$ 7.23	$ 7.98	2%
Huntingdon/Sumas (C$/mmbtu)	$ 5.61	$ 6.46	$ 6.69	$ 7.48	$ 8.23	2%

Offshore West Africa property, plant and equipment has been reduced by $115 million to reflect the impact of a ceiling test impairment charge as at December 31, 2009. The impairment charge has been included in depletion, depreciation and amortization expenses.

5. LONG-TERM DEBT

		2009		2008
Canadian dollar denominated debt				
Bank credit facilities				
Bankers' acceptances	$	**1,897**	$	4,073
Medium-term notes				
5.50% unsecured debentures due December 17, 2010		**400**		400
4.50% unsecured debentures due January 23, 2013		**400**		400
4.95% unsecured debentures due June 1, 2015		**400**		400
		3,097		5,273
US dollar denominated debt				
Senior unsecured notes				
Adjustable rate due May 27, 2009 (2009 – US$nil; 2008 – US$31 million)		**–**		38
US dollar debt securities				
6.70% due July 15, 2011 (2009 and 2008 – US$400 million)		**419**		490
5.45% due October 1, 2012 (2009 and 2008 – US$350 million)		**366**		429
5.15% due February 1, 2013 (2009 and 2008 – US$400 million)		**419**		490
4.90% due December 1, 2014 (2009 and 2008 – US$350 million)		**366**		429
6.00% due August 15, 2016 (2009 and 2008 – US$250 million)		**262**		306
5.70% due May 15, 2017 (2009 and 2008 – US$1,100 million)		**1,151**		1,346
5.90% due February 1, 2018 (2009 and 2008 – US$400 million)		**419**		490
7.20% due January 15, 2032 (2009 and 2008 – US$400 million)		**419**		490
6.45% due June 30, 2033 (2009 and 2008 – US$350 million)		**366**		429
5.85% due February 1, 2035 (2009 and 2008 – US$350 million)		**366**		429
6.50% due February 15, 2037 (2009 and 2008 – US$450 million)		**471**		551
6.25% due March 15, 2038 (2009 and 2008 – US$1,100 million)		**1,151**		1,346
6.75% due February 1, 2039 (2009 and 2008 – US$400 million)		**419**		490
Less – original issue discount on senior unsecured notes and US dollar debt securities (1)		**(22)**		(23)
		6,572		7,730
Fair value impact of interest rate swaps on US dollar debt securities (2)		**38**		68
		6,610		7,798
Long-term debt before transaction costs		**9,707**		13,071
Less: transaction costs (1)(3)		**(49)**		(55)
		9,658		13,016
Less: current portion		**–**		420
	$	**9,658**	$	12,596

(1) The Company has included unamortized original issue discounts and directly attributable transaction costs in the carrying value of the outstanding debt.

(2) The carrying value of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $38 million (2008 – $68 million) 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

As at December 31, 2009, the Company had in place unsecured bank credit facilities of $3,955 million, comprised of:

- a $200 million demand credit facility;
- a revolving syndicated credit facility of $2,230 million maturing June 2012;
- a revolving syndicated credit facility of $1,500 million maturing June 2012; and
- a £15 million demand credit facility related to the Company's North Sea operations.

The revolving syndicated credit facilities are 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 can be made by way of Canadian dollar and US dollar bankers' acceptances, and LIBOR, US base rate and Canadian prime loans.

During 2009, the Company repaid the remaining $2,350 million outstanding on the non-revolving syndicated credit facility related to the acquisition of Anadarko Canada Corporation ("ACC") and cancelled the facility. In March 2007, $1,500 million was repaid.

During 2009, the Company renegotiated its demand credit facility, increasing it to $200 million.

The Company's weighted average interest rate on bank credit facilities outstanding as at December 31, 2009, was 0.8% (2008 – 2.2%).

In addition to the outstanding debt, letters of credit and financial guarantees aggregating $358 million, including $300 million related to Horizon, were outstanding at December 31, 2009.

Medium-term Notes
During 2009, the Company filed a base shelf prospectus that allows for the issue of up to $3,000 million of medium-term notes in Canada until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

Senior Unsecured Notes
During 2009, the remaining US$31 million of senior unsecured notes bearing interest at 6.54% was repaid.

US Dollar Debt Securities
During 2009, the Company filed a base shelf prospectus that allows for the issue of up to US$3,000 million of debt securities in the United States until November 2011. If issued, these securities will bear interest as determined at the date of issuance.

In January 2008, the Company issued US$1,200 million of unsecured notes under a previous US base shelf prospectus, comprised of US$400 million of 5.15% unsecured notes due February 2013, US$400 million of 5.90% unsecured notes due February 2018, and US$400 million of 6.75% unsecured notes due February 2039. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities.

During 2008, US$8 million of US dollar debt securities was repaid.

During 2008, the Company terminated the interest rate swaps that had been designated as a fair value hedge of US$350 million of 5.45% unsecured notes due October 2012. Accordingly, the Company ceased revaluing the related debt for subsequent changes in fair value from the date of termination of the interest rate swaps. The fair value adjustment of $20 million at the date of termination is being amortized to interest expense over the remaining term of the debt, with $14 million remaining at December 31, 2009.

Required Debt Repayments
Required debt repayments are as follows:

Year	Repayment
2010	$ 400
2011	$ 419
2012	$ 366
2013	$ 819
2014	$ 366
Thereafter	$ 5,424

No debt repayments are reflected in the above table for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities. Should the bank credit facilities not be extended by mutual agreement of the Company and the lenders, the amounts outstanding under these facilities would be due in 2012.

6. OTHER LONG-TERM LIABILITIES

	2009	2008
Asset retirement obligations	**$ 1,610**	$ 1,064
Stock-based compensation	**392**	171
Risk management (note 13)	**309**	–
Other	**180**	119
	2,491	1,354
Less: current portion	**643**	230
	$ 1,848	$ 1,124

Asset Retirement Obligations

At December 31, 2009, the Company's total estimated undiscounted costs to settle its asset retirement obligations were approximately $6,606 million (2008 – $4,474 million; 2007 – $4,426 million). Payments to settle these asset retirement obligations will occur on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average credit-adjusted risk-free interest rate of 6.9% (2008 – 6.7%; 2007 – 6.6%). A reconciliation of the discounted asset retirement obligations is as follows:

	2009	2008	2007
Balance – beginning of year	**$ 1,064**	$ 1,074	$ 1,166
Liabilities incurred [1]	**299**	18	21
Liabilities acquired	**–**	3	–
Liabilities disposed	**–**	–	(65)
Liabilities settled	**(48)**	(38)	(71)
Asset retirement obligation accretion	**90**	71	70
Revision of estimates	**276**	(156)	35
Foreign exchange	**(71)**	92	(82)
Balance – end of year	**$ 1,610**	$ 1,064	$ 1,074

(1) During 2009, the Company recognized additional asset retirement obligations related to Horizon and Gabon, Offshore West Africa.

Stock-Based Compensation

The Company recognizes a liability for potential cash settlements under its Option Plan. The current portion represents the maximum amount of the liability payable within the next 12-month period if all vested options are surrendered for cash settlement.

	2009	2008	2007
Balance – beginning of year	**$ 171**	$ 529	$ 744
Stock-based compensation expense (recovery)	**355**	(52)	193
Cash payment for options surrendered	**(94)**	(207)	(375)
Transferred to common shares	**(42)**	(76)	(91)
Capitalized (recovery) to Oil Sands Mining and Upgrading	**2**	(23)	58
Balance – end of year	**392**	171	529
Less: current portion	**365**	159	390
	$ 27	$ 12	$ 139

7. EMPLOYEE FUTURE BENEFITS

In connection with the acquisition of ACC, the Company assumed obligations to provide defined contribution pension benefits to certain ACC employees continuing their employment with the Company, and defined benefit pension and other post-retirement benefits to former ACC employees, under registered and unregistered pension plans.

The estimated future cost of providing defined benefit pension and other post-retirement benefits to former ACC employees is actuarially determined using management's best estimates of demographic and financial assumptions. The discount rate of 5.5% (2008 – 7.0%) used to determine accrued benefit obligations is based on a year-end market rate of interest for high-quality debt instruments with cash flows that match the timing and amount of expected benefit payments. Company contributions to the defined contribution plan are expensed as incurred.

The benefit obligation under the registered pension plan at December 31, 2009 was $29 million (2008 – $27 million). As required by government regulations, the Company has set aside funds with an independent trustee to meet these benefit obligations. As at December 31, 2009, these plan assets had a fair value of $32 million (2008 – $34 million). The unregistered pension plan and other post-retirement benefits are unfunded and have a benefit obligation of $10 million at December 31, 2009 (2008 – $9 million).

8. TAXES

Taxes Other Than Income Tax

	2009	2008	2007
Current PRT expense	**$ 70**	$ 210	$ 97
Deferred PRT expense (recovery)	**15**	(67)	44
Provincial capital taxes and surcharges	**21**	35	24
	$ 106	$ 178	$ 165

Income Tax

The provision for income tax is as follows:

	2009	2008	2007
Current income tax – North America	$ 28	$ 33	$ 96
Current income tax – North Sea	278	340	210
Current income tax – Offshore West Africa	82	128	74
Current income tax expense	388	501	380
Future income tax (recovery) expense	(99)	1,607	(456)
Income tax expense (recovery)	$ 289	$ 2,108	$ (76)

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:

	2009	2008	2007
Canadian statutory income tax rate	29.1%	29.8%	32.5%
Income tax provision at statutory rate	$ 576	$ 2,166	$ 877
Effect on income taxes of:			
Deductible UK petroleum revenue tax	(43)	(72)	(71)
Foreign and domestic tax rate differentials	(127)	(5)	(25)
North America income tax rate and other legislative changes	(19)	(19)	(864)
Côte d'Ivoire income tax rate changes	–	(22)	–
Non-taxable portion of foreign exchange (gain) loss	(92)	127	(96)
Stock options exercised in shares	27	6	63
Other	(33)	(73)	40
Income tax expense (recovery)	$ 289	$ 2,108	$ (76)

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

	2009	2008
Future income tax liabilities		
Property, plant and equipment	$ 6,992	$ 6,303
Timing of partnership items	1,127	1,276
Unrealized foreign exchange gain on long-term debt	152	13
Unrealized risk management activities	–	651
Other	31	–
Future income tax assets		
Asset retirement obligations	(499)	(372)
Loss carryforwards for income tax	(84)	(62)
Stock-based compensation	(83)	(38)
Unrealized risk management activities	(69)	–
Other	–	(7)
Deferred petroleum revenue tax	(26)	(43)
Net future income tax liability	7,541	7,721
Less: current portion of future income tax (asset) liability	(146)	585
Future income tax liability	$ 7,687	$ 7,136

During 2009, substantively enacted or enacted income tax rate changes resulted in a reduction of future income tax liabilities of $19 million in British Columbia.

During 2008, substantively enacted or enacted income tax rate changes resulted in a reduction of future income tax liabilities of approximately $19 million in British Columbia and approximately $22 million in Côte d'Ivoire.

During 2007, substantively enacted or enacted income tax rate and other legislative changes resulted in a reduction of future income tax liabilities of approximately $864 million in North America.

As a result of enacted income tax rate changes in 2007, the Canadian Federal corporate income tax rate is being reduced from 21% in 2007 to 15% in 2012.

The Company is subject to income tax reassessments arising in the normal course. The Company does not believe that any liabilities ultimately arising from these reassessments will be material.

9. SHARE CAPITAL

Authorized

200,000 Class 1 preferred shares with a stated value of $10.00 each.

Unlimited number of common shares without par value.

Issued

	2009			2008		
Common shares	**Number of shares** (thousands)		**Amount**	Number of shares (thousands)		Amount
Balance – beginning of year	**540,991**	**$**	**2,768**	539,729	$	2,674
Issued upon exercise of stock options	**1,336**		**24**	1,262		18
Previously recognized liability on stock options exercised for common shares	**–**		**42**	–		76
Balance – end of year	**542,327**	**$**	**2,834**	540,991	$	2,768

Dividend Policy

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

On March 3, 2010, the Board of Directors set the Company's regular quarterly dividend at $0.15 per common share (2009 – $0.105 per common share; 2008 – $0.10 per common share).

Normal Course Issuer Bid

On March 3, 2010 the Board of Directors approved a resolution to file with the Toronto Stock Exchange a notice of intention to purchase by way of normal course issuer bid up to 2.5% of the Company's issued and outstanding common shares. Subject to acceptance by the Toronto Stock Exchange of the Notice of Intention, the purchases would be made through the facilities of the Toronto Stock Exchange and the New York Stock Exchange.

Share split

On March 3, 2010, the Company's Board of Directors approved a resolution to subdivide the Company's common shares on a two for one basis, subject to shareholder approval. The proposal will be voted on at the Company's Annual and Special Meeting of Shareholders to be held on May 6, 2010.

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 option.

The following table summarizes information relating to stock options outstanding at December 31, 2009 and 2008:

	2009			2008		
	Stock options (thousands)		**Weighted average exercise price**	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**30,962**	**$**	**51.94**	30,659	$	47.23
Granted	**6,736**	**$**	**67.91**	7,705	$	53.38
Surrendered for cash settlement	**(2,833)**	**$**	**27.31**	(3,702)	$	25.60
Exercised for common shares	**(1,336)**	**$**	**17.99**	(1,262)	$	14.61
Forfeited	**(1,423)**	**$**	**59.55**	(2,438)	$	56.56
Outstanding – end of year	**32,106**	**$**	**58.54**	30,962	$	51.94
Exercisable – end of year	**10,969**	**$**	**53.90**	8,809	$	44.58

The range of exercise prices of stock options outstanding and exercisable at December 31, 2009 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**
$16.89 – $19.99	338	0.28	$ 17.36	331	$ 17.36
$20.00 – $29.99	1,993	0.35	$ 25.61	1,342	$ 25.35
$30.00 – $39.99	755	0.63	$ 33.28	528	$ 33.29
$40.00 – $49.99	6,523	4.06	$ 46.38	1,252	$ 45.96
$50.00 – $59.99	4,700	1.85	$ 58.11	2,609	$ 58.04
$60.00 – $69.99	10,601	3.84	$ 65.58	2,503	$ 61.54
$70.00 – $79.99	6,412	3.32	$ 70.82	2,363	$ 70.72
$80.00 – $89.99	–	–	$ –	–	$ –
$90.00 – $92.50	784	4.53	$ 92.50	41	$ 92.50
	32,106	3.18	$ 58.54	10,969	$ 53.90

10. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

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

	2009	2008
Derivative financial instruments designated as cash flow hedges	**$ 76**	$ 119
Foreign currency translation adjustment	**(180)**	143
	$ (104)	$ 262

During the next 12 months, $1 million is expected to be reclassified to net earnings from accumulated other comprehensive income.

During 2008, the Company determined that its operations in Offshore West Africa were operationally and financially independent and the current rate method of translation was adopted for translation of the financial statements of its Offshore West African subsidiaries. This change was applied prospectively and increased assets by $32 million, decreased liabilities by $4 million and increased accumulated other comprehensive income by $36 million.

11. 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 each reporting date. The Company is subject to certain financial covenants in its long-term debt agreements and is in compliance with these covenants.

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 non-GAAP 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 aims over time to maintain its debt to book capitalization ratio in the range of 35% to 45%. However, the Company may exceed the high end of such target range if it is investing in capital projects, undertaking acquisitions, or in periods of lower commodity prices. The Company may be below the low end of the target range when cash flow from operating activities is greater than current investment activities. The ratio is currently below the target range at 33%.

Readers are cautioned that the debt to book capitalization ratio is not defined by GAAP and this financial measure may not be comparable to similar measures presented by other companies. Further, there can be 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 at some point in the future.

	2009	2008
Long-term debt (1)	**$ 9,658**	$ 13,016
Total shareholders' equity	**$ 19,426**	$ 18,374
Debt to book capitalization	**33%**	41%

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

12. NET EARNINGS PER COMMON SHARE

	2009	2008	2007
Weighted average common shares outstanding – basic and diluted (thousands of shares)	**541,925**	540,647	539,336
Net earnings – basic and diluted	**$ 1,580**	$ 4,985	$ 2,608
Net earnings per common share – basic and diluted	**$ 2.92**	$ 9.22	$ 4.84

13. FINANCIAL INSTRUMENTS

The carrying values of the Company's financial instruments by category are as follows:

	2009		
Asset (liability)	**Loans and receivables at amortized cost**	**Held for trading at fair value**	**Other financial liabilities at amortized cost**
Cash and cash equivalents	**$ –**	**$ 13**	**$ –**
Accounts receivable	**1,148**	**–**	**–**
Other long-term assets	**–**	**–**	**–**
Accounts payable	**–**	**–**	**(240)**
Accrued liabilities	**–**	**–**	**(1,522)**
Other long-term liabilities	**–**	**(309)**	**(167)**
Long-term debt	**–**	**–**	**(9,658)**
	$ 1,148	**$ (296)**	**$ (11,587)**

	2008		
Asset (liability)	Loans and receivables at amortized cost	Held for trading at fair value	Other financial liabilities at amortized cost
Cash and cash equivalents	$ –	$ 27	$ –
Accounts receivable	1,059	–	–
Other long-term assets	–	2,119	–
Accounts payable	–	–	(383)
Accrued liabilities	–	–	(1,802)
Other long-term liabilities	–	–	(105)
Long-term debt (1)	–	–	(13,016)
	$ 1,059	$ 2,146	$ (15,306)

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

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

	2009		
	Carrying value	**Fair value**	
Asset (liability) (1)		**Level 1**	**Level 2**
Other long-term assets	**$ –**	**$ –**	**$ –**
Other long-term liabilities	**(309)**	**–**	**(309)**
Fixed-rate long-term debt (2) (3)	**(7,761)**	**(8,212)**	**–**
	$ (8,070)	**$ (8,212)**	**$ (309)**

	2008		
	Carrying value	Fair value	
Asset (liability) (1)		Level 1	Level 2
Other long-term assets	$ 2,119	$ –	$ 2,119
Other long-term liabilities	–	–	–
Fixed-rate long-term debt (2) (3)	(8,943)	(7,649)	–
	$ (6,824)	$ (7,649)	$ 2,119

(1) Excludes financial assets and liabilities where book value 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) The carrying values of US$350 million of 5.45% notes due October 2012 and US$350 million of 4.90% notes due December 2014 have been adjusted by $38 million (2008 – $68 million) to reflect the fair value impact of hedge accounting.

(3) The fair value of fixed-rate long-term debt has been determined based on quoted market prices.

Risk Management

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)	2009 Risk management mark-to-market	2008 Risk management mark-to-market
Balance – beginning of year	$ 2,119	$ (1,474)
Net cost of outstanding put options	–	297
Net change in fair value of outstanding derivative financial instruments attributable to:		
Risk management activities	(1,991)	3,090
Interest expense	(25)	60
Foreign exchange	(338)	449
Other comprehensive income	(78)	18
Settlement of interest rate swaps	4	(20)
	(309)	2,420
Add: put premium financing obligations (1)	–	(301)
Balance – end of year	(309)	2,119
Less: current portion	(182)	1,851
	$ (127)	$ 268

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

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

	2009	2008	2007
Net realized risk management (gain) loss	$ (1,253)	$ 1,860	$ 162
Net unrealized risk management loss (gain)	1,991	(3,090)	1,400
	$ 738	$ (1,230)	$ 1,562

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 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. At December 31, 2009, the Company had the following net derivative financial instruments outstanding to manage its commodity price exposures:

	Remaining term	Volume	Weighted average price	Index
Crude oil				
Crude oil price collars	Jan 2010 – Mar 2010	6,000 bbl/d	US$60.00 – US$105.15	WTI
	Jan 2010 – Jun 2010	100,000 bbl/d	US$60.00 – US$90.13	WTI
	Jan 2010 – Sep 2010	50,000 bbl/d	US$65.00 – US$105.49	WTI
	Jan 2010 – Dec 2010	50,000 bbl/d	US$60.00 – US$75.08	WTI
	Jul 2010 – Dec 2010	50,000 bbl/d	US$65.00 – US$108.94	WTI

	Remaining term	Volume	Weighted average price	Index
Natural gas				
Natural gas price collars (1)	Jan 2010 – Dec 2010	220,000 GJ/d	C$6.00 – C$8.00	AECO

(1) Subsequent to December 31, 2009, the Company entered into 400,000 GJ/d of C$4.50 – C$6.30 natural gas AECO collars for the period April to September 2010.

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.

There were no commodity derivative financial instruments designated as hedges at December 31, 2009.

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 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, 2009, the Company had the following interest rate swap contracts outstanding:

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jan 2010 – Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Jan 2010 – Feb 2011	C$300	1.0680%	3 month CDOR (2)
	Jan 2010 – Feb 2012	C$200	1.4475%	3 month CDOR (2)

(1) London Interbank Offered Rate.
(2) Canadian Dealer Offered Rate.

All fixed to floating interest rate related derivative financial instruments designated as hedges at December 31, 2009 were classified as fair value hedges.

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 and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies in its subsidiaries and in the carrying value of its self-sustaining 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 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, 2009, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency					
Swaps	Jan 2010 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2010 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2010 – Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments designated as hedges at December 31, 2009 were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2009, the Company had US$1,062 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less.

Financial Instrument Sensitivities

The following table summarizes the annualized sensitivities of the Company's net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2009, 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 can not be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear.

	Impact on net earnings	Impact on other comprehensive income
Commodity price risk		
Increase WTI US$1.00/bbl	$ (21)	$ –
Decrease WTI US$1.00/bbl	$ 20	$ –
Increase AECO C$0.10/mcf	$ (4)	$ –
Decrease AECO C$0.10/mcf	$ 4	$ –
Interest rate risk		
Increase interest rate 1%	$ (12)	$ 14
Decrease interest rate 1%	$ 8	$ (18)
Foreign currency exchange rate risk		
Increase exchange rate by US$0.01	$ (29)	$ –
Decrease exchange rate by US$0.01	$ 29	$ –

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, 2009, substantially all of the Company's accounts receivables 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, 2009, the Company had net risk management assets of $7 million with specific counterparties related to derivative financial instruments (December 31, 2008 – $2,119 million).

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, 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 are as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 240	$ –	$ –	$ –
Accrued liabilities	$ 1,522	$ –	$ –	$ –
Risk management	$ 182	$ 15	$ 48	$ 64
Other long-term liabilities	$ 96	$ 18	$ 32	$ 21
Long-term debt (1)	$ 400	$ 419	$ 1,551	$ 5,424

(1) The long-term debt represents principal repayments only and does not reflect fair value adjustments, original issue discounts or transaction costs. No debt repayments are reflected for $1,897 million of revolving bank credit facilities due to the extendable nature of the facilities.

14. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2010	2011	2012	2013	2014	Thereafter
Product transportation and pipeline	$ 207	$ 162	$ 136	$ 125	$ 126	$ 1,051
Offshore equipment operating leases	$ 155	$ 124	$ 103	$ 102	$ 101	$ 261
Offshore drilling	$ 49	$ –	$ –	$ –	$ –	$ –
Asset retirement obligations (1)	$ 16	$ 20	$ 21	$ 31	$ 39	$ 6,479
Office leases	$ 25	$ 19	$ 3	$ 2	$ 2	$ –
Other	$ 271	$ 67	$ 23	$ 15	$ 12	$ 34

(1) Amounts represent management's estimate of the future undiscounted payments to settle asset retirement obligations related to resource properties, facilities, and production platforms, based on current legislation and industry operating practices. Amounts disclosed for the period 2010 – 2014 represent the minimum required expenditures to meet these obligations. Actual expenditures in any particular year may exceed these minimum amounts.

The Company is defendant and plaintiff in a number of legal actions that arise in the normal course of business. In addition, the Company is subject to certain contractor 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.

16. SEGMENTED INFORMATION

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

The Company's Oil Sands Mining and Upgrading is a separate segment from conventional crude oil and natural gas activities as the bitumen will be recovered through mining operations.

	Conventional Crude Oil and Natural Gas								
	North America			North Sea			Offshore West Africa		
	2009	2008	2007	**2009**	2008	2007	**2009**	2008	2007
Segmented revenue	**$ 7,973**	$ 13,496	$ 10,149	**$ 961**	$ 1,769	$ 1,597	**$ 913**	$ 944	$ 776
Less: royalties	**(825)**	(1,876)	(1,318)	**(2)**	(4)	(3)	**(81)**	(143)	(70)
Revenue, net of royalties	**7,148**	11,620	8,831	**959**	1,765	1,594	**832**	801	706
Segmented expenses									
Production	**1,748**	1,881	1,642	**376**	457	432	**179**	102	94
Transportation and blending	**1,213**	1,975	1,595	**8**	10	16	**1**	1	1
Depletion, depreciation and amortization	**2,060**	2,236	2,350	**261**	317	340	**335**	132	165
Asset retirement obligation accretion	**41**	42	38	**24**	27	30	**4**	2	2
Realized risk management activities	**(880)**	1,861	129	**(373)**	(1)	33	**–**	–	–
Total segmented expenses	**4,182**	7,995	5,754	**296**	810	851	**519**	237	262
Segmented earnings before the following	**$ 2,966**	$ 3,625	$ 3,077	**$ 663**	$ 955	$ 743	**$ 313**	$ 564	$ 444
Non-segmented expenses									
Administration									
Stock-based compensation expense (recovery)									
Interest, net									
Unrealized risk management activities									
Foreign exchange (gain) loss									
Total non-segmented expenses									
Earnings before taxes									
Taxes other than income tax									
Current income tax expense									
Future income tax (recovery) expense									
Net earnings									

15. SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION

Changes in non-cash working capital were as follows:

	2009	2008	2007
Changes in non-cash working capital			
Accounts receivable and other	**$ (276)**	$ 111	$ 334
Accounts payable	**(151)**	(4)	(456)
Accrued liabilities	**(429)**	(15)	(402)
Net changes in non-cash working capital	**$ (856)**	$ 92	$ (524)
Relating to:			
Operating activities	**$ (235)**	$ (189)	$ (346)
Financing activities	**(12)**	46	8
Investing activities	**(609)**	235	(186)
	$ (856)	$ 92	$ (524)

Other cash flow information:	2009	2008	2007
Interest paid	**$ 516**	$ 574	$ 556
Taxes other than income tax paid	**$ 52**	$ 300	$ 116
Current income tax paid	**$ 216**	$ 258	$ 302

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

	Oil Sands Mining and Upgrading			Midstream			Inter–segment elimination and other			Total		
	2009	2008	2007	2009	2008	2007	2009	2008	2007	2009	2008	2007
	$ 1,253	$ –	$ –	**$ 72**	$ 77	$ 74	**$ (94)**	$ (113)	$ (53)	**$11,078**	$16,173	$12,543
	(36)	–	–	**–**	–	–	**8**	6	–	**(936)**	(2,017)	(1,391)
	1,217	–	–	**72**	77	74	**(86)**	(107)	(53)	**10,142**	14,156	11,152
	683	–	–	**19**	25	22	**(18)**	(14)	(6)	**2,987**	2,451	2,184
	41	–	–	**–**	–	–	**(45)**	(50)	(42)	**1,218**	1,936	1,570
	187	–	–	**9**	8	8	**(33)**	(10)	–	**2,819**	2,683	2,863
	21	–	–	**–**	–	–	**–**	–	–	**90**	71	70
	–	–	–	**–**	–	–	**–**	–	–	**(1,253)**	1,860	162
	932	–	–	**28**	33	30	**(96)**	(74)	(48)	**5,861**	9,001	6,849
	$ 285	$ –	$ –	**$ 44**	$ 44	$ 44	**$ 10**	$ (33)	$ (5)	**4,281**	5,155	4,303
										181	180	208
										355	(52)	193
										410	128	276
										1,991	(3,090)	1,400
										(631)	718	(471)
										2,306	(2,116)	1,606
										1,975	7,271	2,697
										106	178	165
										388	501	380
										(99)	1,607	(456)
										$ 1,580	$ 4,985	$ 2,608

Capital Expenditures

	2009			2008		
	Net expenditures	**Non cash and fair value changes [1]**	**Capitalized costs**	Net expenditures	Non cash and fair value changes [1]	Capitalized costs
Conventional crude oil and natural gas						
North America	**$ 1,663**	**$ 65**	**$ 1,728**	$ 2,344	$ (7)	$ 2,337
North Sea	**168**	**146**	**314**	319	(127)	192
Offshore West Africa	**544**	**111**	**655**	811	6	817
Other	**2**	**–**	**2**	1	–	1
	2,377	**322**	**2,699**	3,475	(128)	3,347
Oil Sands Mining and Upgrading [2]	**553**	**355**	**908**	3,912	10	3,922
Midstream	**6**	**–**	**6**	9	–	9
Head office	**13**	**–**	**13**	17	–	17
	$ 2,949	**$ 677**	**$ 3,626**	$ 7,413	$ (118)	$ 7,295

(1) Asset retirement obligations, future income tax adjustments related to differences between carrying value and tax value, and other fair value adjustments.

(2) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest, stock-based compensation, and the impact of intersegment eliminations.

Segmented Assets

	2009	2008
Conventional crude oil and natural gas		
North America	**$ 22,994**	$ 24,875
North Sea	**1,968**	2,638
Offshore West Africa	**2,033**	2,013
Other	**42**	64
Oil Sands Mining and Upgrading	**13,621**	12,677
Midstream	**306**	315
Head office	**60**	68
	$ 41,024	$ 42,650

17. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Company's consolidated financial statements have been prepared in accordance with Canadian GAAP. These principles conform in all material respects with US GAAP except for those noted below. Certain differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings (loss) as reported:

(millions of Canadian dollars, except per common share amounts)	Notes	**2009**	2008	2007
Net earnings – Canadian GAAP		**$ 1,580**	$ 4,985	$ 2,608
Adjustments				
Depletion, net of taxes of $7 million (2008 – $2,503 million; 2007 – $1 million)	(A,B,C,D)	**(273)**	(6,169)	(10)
Stock-based compensation, net of taxes of $51 million (2008 – $32 million; 2007 – $3 million)	(B)	**(154)**	(76)	(22)
Future income taxes	(F)	**–**	234	(234)
Net earnings (loss) – US GAAP		**$ 1,153**	$ (1,026)	$ 2,342
Net earnings (loss) – US GAAP per common share				
Basic		**$ 2.13**	$ (1.90)	$ 4.34
Diluted	(E)	**$ 2.13**	$ (1.90)	$ 4.32

Comprehensive income (loss) under US GAAP would be as follows:

(millions of Canadian dollars)	Notes	**2009**	2008	2007
Comprehensive income – Canadian GAAP		**$ 1,214**	$ 5,175	$ 2,534
US GAAP earnings adjustments		**(427)**	(6,011)	(266)
Comprehensive income (loss) – US GAAP		**$ 787**	$ (836)	$ 2,268

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

(millions of Canadian dollars)	Notes	**2009** Canadian GAAP	Increase (Decrease)	US GAAP
Current assets		**$ 1,891**	**$ 103**	**$ 1,994**
Property, plant and equipment	(A,B,C,D)	**39,115**	**(8,824)**	**30,291**
Other long-term assets	(G)	**18**	**49**	**67**
		$ 41,024	**$ (8,672)**	**$ 32,352**
Current liabilities	(B)	**$ 2,405**	**$ 387**	**$ 2,792**
Long-term debt	(G)	**9,658**	**49**	**9,707**
Other long-term liabilities	(B)	**1,848**	**35**	**1,883**
Future income tax	(A,B,C,D,F)	**7,687**	**(2,474)**	**5,213**
Share capital		**2,834**	**–**	**2,834**
Retained earnings		**16,696**	**(6,669)**	**10,027**
Accumulated other comprehensive income		**(104)**	**–**	**(104)**
		$ 41,024	**$ (8,672)**	**$ 32,352**

(millions of Canadian dollars)	Notes	2008 Canadian GAAP	Increase (Decrease)	US GAAP
Current assets		$ 3,392	$ –	$ 3,392
Property, plant and equipment	(A,B,C,D)	38,966	(8,551)	30,415
Other long-term assets	(G)	292	55	347
		$ 42,650	$ (8,496)	$ 34,154
Current liabilities	(B)	$ 3,420	$ 150	$ 3,570
Long-term debt	(G)	12,596	55	12,651
Other long-term liabilities	(B)	1,124	15	1,139
Future income tax	(A,B,C,D,F)	7,136	(2,474)	4,662
Share capital		2,768	–	2,768
Retained earnings		15,344	(6,242)	9,102
Accumulated other comprehensive income		262	–	262
		$ 42,650	$ (8,496)	$ 34,154

Notes:

(A) Under Canadian full cost accounting guidance, costs capitalized in each country cost centre are limited to an amount equal to the future net revenues from proved and probable reserves using estimated future prices and costs discounted at the risk-free rate, plus the carrying amount of unproved properties and major development projects (the "ceiling test") as described in note 1(I). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices using the average first-day-of-the-month price during the previous 12-month period and costs as at the balance sheet date, and are discounted at 10%. Capitalized costs and future net revenues are determined on a net of tax basis. In addition, beginning in 2009, the Company's Oil Sands Mining and Upgrading activities are included in the Company's US GAAP full cost oil and gas cost center for Canada for ceiling test purposes. These differences in applying the ceiling test to current and prior years resulted in the recognition of ceiling test impairments under US GAAP, which reduced property, plant and equipment by $8,951 million in 2009 (2008 – $8,697 million; 2007 – $36 million).

For the year ended December 31, 2009, US GAAP net earnings would have decreased by $815 million (2008 – $6,164 million), net of income taxes of $178 million (2008 – $2,501 million) to reflect the impact of a current year ceiling test impairment. In addition, the impact of prior ceiling test impairments would have increased US GAAP net earnings by $551 million (2008 – increased by $3 million; 2007 – decreased by $4 million), net of income taxes of $188 million (2008 – $1 million; 2007 – $8 million) to reflect the impact of lower depletion charges. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

During 2009, the US Securities and Exchange Commission adopted revisions to its oil and gas reporting disclosures contained in Regulation S-K and Topic 932 "Extractive Activities – Oil and Gas" (a summary of the requirements included in Regulation S-X). These revisions change the price basis for calculating oil and gas reserves from a single-day, year-end price to a monthly average price based on "first-day-of-the-month" prices. These revisions impacted the reserves used in the Company's calculation of the ceiling test under US GAAP at December 31, 2009 and will impact the calculation of depletion in future periods. In addition, oil and gas activities are now determined based on the end product, rather than the method of extraction. As a result, the Company's Oil and Sands Mining and Upgrading operations are now included in its full cost oil and gas cost center for Canada. These revisions are effective for filings made on or after January 1, 2010, and will be applied prospectively with no retroactive restatement.

(B) The Company accounts for its stock-based compensation liability under Canadian GAAP using the intrinsic value method, as described in note 1(P). Under US GAAP, effective January 1, 2006, the Company would have adopted Financial Accounting Standards Board Statement (FASB) Topic 718 "Compensation – Stock Compensation" (previously FAS 123(R)), which requires companies to account for all stock-based compensation liabilities using the fair value method, where fair value is measured using an option pricing model. The Company uses the Black Scholes option pricing model to determine the fair value of its stock-based compensation liability for US GAAP purposes. The previous US GAAP standard, FAS 123, required companies to account for cash settled stock-based compensation liabilities using the intrinsic value method. For the year ended December 31, 2009, US GAAP net earnings would have decreased by $154 million (2008 – $76 million; 2007 – $22 million), net of income taxes of $51 million (2008 – $32 million; 2007 – $3 million) related to the different valuation methodologies. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item. In addition, US GAAP net earnings would have decreased by $1 million (2008 - $nil; 2007 - $nil), net of income taxes of $nil (2008 - $nil; 2007 - $nil) related to the impact of the change in capitalized stock-based compensation on depletion, depreciation and amortization expenses.

(C) Under US GAAP, the foreign currency component of a business combination is not eligible for cash flow hedging. The impact of prior year adjustments would have decreased US GAAP net earnings by $7 million for the year ended December 31, 2009 (2008 – $8 million; 2007 – $6 million), net of income taxes of $3 million (2008 – $3 million; 2007 – $7 million), to reflect the impact of higher depletion charges. The 2007 income tax effect includes the effect of enacted Canadian income tax rate changes on this item.

(D) Under Canadian GAAP, the Company began capitalizing interest on the Horizon Project when the Board of Directors approval was received in 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest would have been capitalized to the costs of construction beginning in 2004. As a result of applying US GAAP, an additional $27 million would have been capitalized to property, plant and equipment in 2004. During 2009, Horizon Phase 1 assets were completed and available for their intended use. Accordingly, capitalization of all associated Phase 1 development costs, including capitalized interest ceased and depletion, depreciation and amortization of these assets commenced. For the year ended December 31, 2009, US GAAP net earnings would have decreased by $1 million (2008 – $nil; 2007 – $nil), net of income taxes of $nil (2008 – $nil; 2007 – $nil).

(E) Under Canadian GAAP, the Company is not required to include potential common shares related to stock options in the calculation of diluted earnings per share as the Company has recorded the potential settlement of the stock options as a liability. Under US GAAP Topic 260 "Earnings Per Share" (previously FAS 128 "Earnings Per Share"), the Company would have included potential common shares related to stock options in the calculation of diluted earnings per share. For the year ended December 31, 2009, nil additional shares would have been included in the calculation of diluted earnings per share for US GAAP (2008 – nil additional shares; 2007 – 3,376,000 additional shares).

(F) Under Canadian GAAP, the effects of income tax changes are recognized when the changes are considered substantively enacted. Under US GAAP, the income tax changes would not be recognized until the changes are enacted into law. For the years ended December 31, 2008 and 2007, the differences between substantively enacted and enacted tax legislation resulted in a difference in timing of the recognition of a $234 million future income tax recovery.

(G) Under Canadian GAAP, debt issue costs on long-term debt must be included in the carrying value of the related debt. Under US GAAP, these items must be recorded as a deferred charge. Application of US GAAP would have resulted in the balance sheet reclassification of $49 million of debt issue costs from long-term debt to deferred charges in 2009 (2008 – $55 million; 2007 – $51 million).

(H) In December 2007, the FASB issued Topic 805 "Business Combinations" (previously FAS 141(R) "Business Combinations"), which replaced FAS 141 effective for fiscal years beginning after December 15, 2008. Topic 805 retains the purchase method of accounting and requires assets acquired and liabilities assumed in a business combination to be measured at fair value at the date of acquisition. The standard also requires acquisition-related costs and restructuring costs to be recognized separately from the business combination. This standard is to be applied prospectively to all business combinations subsequent to the effective date and does not require restatement of previously completed business combinations. The adoption of this standard did not result in a US GAAP reconciling item.

SUPPLEMENTARY OIL & 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 is reconciled to the financial information prepared in accordance with generally accepted accounting principles in the United States ("US GAAP").

NET PROVED CRUDE OIL AND NATURAL GAS RESERVES

The Company retains qualified independent reserves evaluators to evaluate the Company's proved crude oil and natural gas reserves.

- For the year ended December 31, 2009, the reports by GLJ Petroleum Consultants Ltd. ("GLJ") covered 100% of the Company's synthetic crude oil reserves. With the inclusion of the non-traditional resources within the definition of "oil and gas producing activities" within the SEC's modernization of oil and gas reporting rules ("Final Rule"), effective January 1, 2010, these reserves volumes are now included within the Company's crude oil and natural gas reserves totals.

- For the year ended December 31, 2009, and 2008, the reports by Sproule Associates Limited ("Sproule") covered 100% of the Company's bitumen, coal bed methane, crude oil and natural gas liquids and natural gas reserves.

- For the years ended December 31, 2007, and 2006, the reports by Sproule and Ryder Scott Company covered 100% of the Company's bitumen, coal bed methane, crude oil and natural gas liquids and natural gas reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, under the Final Rule, are the estimated quantities of oil and gas that geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, under known reservoirs under existing economic conditions, operating methods and government regulations. Proved developed reserves are reserves 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 is the extraction is by means not involving a well.

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 table summarizes the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2009, 2008, 2007, and 2006:

Crude Oil and NGLs (mmbbl)	**Synthetic Crude Oil** [1]	**Bitumen** [2]	**Crude Oil & NGLs**	**North America Total**	**North Sea**	**Offshore West Africa**	**Total**
Net Proved Reserves							
Reserves, December 31, 2006				887	299	130	1,316
Extensions and discoveries				30	–	–	30
Improved recovery				13	6	–	19
Purchases of reserves in place				1	–	–	1
Sales of reserves in place				–	(3)	–	(3)
Production				(77)	(20)	(10)	(107)
Revisions of prior estimates [3]				66	28	8	102
Reserves, December 31, 2007				920	310	128	1,358
Extensions and discoveries				51	–	–	51
Improved recovery				17	6	4	27
Purchases of reserves in place				–	–	–	–
Sales of reserves in place				–	–	–	–
Production				(76)	(17)	(8)	(101)
Economic revisions due to prices				28	(81)	8	(45)
Revisions of prior estimates				8	38	10	56
Reserves, December 31, 2008	**–**	**690**	**258**	**948**	**256**	**142**	**1,346**
Extensions and discoveries	**–**	**24**	**6**	**30**	**–**	**–**	**30**
Improved recovery	**–**	**8**	**75**	**83**	**–**	**–**	**83**
SEC reliable technology [4]	**–**	**7**	**–**	**7**	**–**	**–**	**7**
SEC rule transition [5]	**1,650**	**–**	**–**	**1,650**	**–**	**–**	**1,650**
Purchases of reserves in place	**–**	**–**	**1**	**1**	**–**	**–**	**1**
Sales of reserves in place	**–**	**–**	**–**	**–**	**–**	**–**	**–**
Production	**–**	**(49)**	**(24)**	**(73)**	**(14)**	**(11)**	**(98)**
Economic revisions due to prices	**–**	**(64)**	**(8)**	**(72)**	**57**	**(4)**	**(19)**
Revisions of prior estimates	**–**	**79**	**11**	**90**	**(59)**	**(4)**	**27**
Reserves, December 31, 2009	**1,650**	**695**	**319**	**2,664**	**240**	**123**	**3,027**
Net proved developed reserves							
December 31, 2006				420	214	63	697
December 31, 2007				426	240	70	736
December 31, 2008				428	97	107	632
December 31, 2009	**1,589**	**268**	**204**	**2,061**	**94**	**106**	**2,261**

(1) 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 synthetic crude oil is now included in the Company's crude oil and natural gas reserves totals.

(2) Bitumen as defined by the SEC, under the Final Rule, "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 oil reserves have been classified as bitumen. Prior to December 31, 2009, these reserves would have been classified within the Company's conventional crude oil and NGL totals.

(3) Revisions of prior estimates for the year ended December 31, 2007 include the impact of economic revisions due to prices.

(4) SEC reliable technology accounts for reserves volumes added due to the reserves rule changes.

(5) For continuity purposes, with respect to the transition from Industry Guide 7 into the SEC's Final Rule, the following SCO table has been provided to illustrate the changes in the Company's Horizon SCO reserves for the 2009 year.

Horizon SCO Reserves	Net proved (mmbbl)
Reserves, December 31, 2008	1,946
Production	(18)
Economic revisions due to prices	(307)
Revisions of prior estimates	29
Reserves, December 31, 2009	**1,650**

Natural Gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net Proved Reserves				
Reserves, December 31, 2006	3,705	37	56	3,798
Extensions and discoveries	134	–	–	134
Improved recovery	132	3	–	135
Purchases of reserves in place	12	–	–	12
Sales of reserves in place	–	–	–	–
Production	(503)	(5)	(4)	(512)
Revisions of prior estimates (1)	41	46	12	99
Reserves, December 31, 2007	3,521	81	64	3,666
Extensions and discoveries	140	–	–	140
Improved recovery	52	(1)	6	57
Purchases of reserves in place	77	–	–	77
Sales of reserves in place	(1)	–	–	(1)
Production	(449)	(4)	(4)	(457)
Economic revisions due to prices	(19)	(56)	6	(69)
Revisions of prior estimates	202	47	22	271
Reserves, December 31, 2008	**3,523**	**67**	**94**	**3,684**
Extensions and discoveries	**92**	–	–	**92**
Improved recovery	**11**	–	–	**11**
Purchases of reserves in place	**15**	–	–	**15**
Sales of reserves in place	**(6)**	–	–	**(6)**
Production	**(443)**	**(4)**	**(6)**	**(453)**
Economic revisions due to prices	**(335)**	**12**	**(4)**	**(327)**
Revisions of prior estimates	**170**	**(8)**	**1**	**163**
Reserves, December 31, 2009	**3,027**	**67**	**85**	**3,179**
Net proved developed reserves				
December 31, 2006	2,934	17	12	2,963
December 31, 2007	2,731	58	53	2,842
December 31, 2008	2,690	45	89	2,824
December 31, 2009	**2,333**	**45**	**81**	**2,459**

(1) Revisions of prior estimates for the year ended December 31, 2007 include the impact of economic revisions due to prices.

CAPITALIZED COSTS RELATED TO CRUDE OIL AND NATURAL GAS ACTIVITIES

	2009				
(millions of Canadian dollars)	**North America (1)**	**North Sea**	**Offshore West Africa**	**Other**	**Total**
Proved properties	**$ 49,052**	**$ 3,875**	**$ 2,195**	**$ 14**	**$ 55,136**
Unproved properties	**2,854**	**4**	**666**	**28**	**3,552**
	51,906	**3,879**	**2,861**	**42**	**58,688**
Less: accumulated depletion and depreciation	**(24,216)**	**(3,260)**	**(1,170)**	**(14)**	**(28,660)**
Net capitalized costs	**$ 27,690**	**$ 619**	**$ 1,691**	**$ 28**	**$ 30,028**

(1) As at December 31, 2009, the Company's Oil Sands Mining and Upgrading segment has been included in North America capitalized costs in accordance with revisions to the US Securities and Exchange Commission oil and gas disclosures in Regulations S–K and S–X and FASB Topic 932 – "Extractive Activities – Oil and Gas".

	2008				
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Other	Total
Proved properties	$ 34,386	$ 4,155	$ 2,076	$ 14	$ 40,631
Unproved properties	2,271	12	595	26	2,904
	36,657	4,167	2,671	40	43,535
Less: accumulated depletion and depreciation	(21,857)	(3,366)	(777)	(14)	(26,014)
Net capitalized costs	$ 14,800	$ 801	$ 1,894	$ 26	$ 17,521

(millions of Canadian dollars)	North America	North Sea	2007 Offshore West Africa	Other	Total
Proved properties	$ 32,061	$ 3,164	$ 1,695	$ 14	$ 36,934
Unproved properties	2,259	10	138	25	2,432
	34,320	3,174	1,833	39	39,366
Less: accumulated depletion and depreciation	(12,213)	(1,446)	(645)	(14)	(14,318)
Net capitalized costs	$ 22,107	$ 1,728	$ 1,188	$ 25	$ 25,048

COSTS INCURRED IN CRUDE OIL AND NATURAL GAS ACTIVITIES

(millions of Canadian dollars)	**North America** [(1)]	**North Sea**	**2009 Offshore West Africa**	**Other**	**Total**
Property acquisitions					
Proved	**$ 6**	**$ –**	**$ –**	**$ –**	**$ 6**
Unproved	**69**	**–**	**–**	**–**	**69**
Exploration	**173**	**36**	**1**	**–**	**210**
Development	**1,480**	**277**	**654**	**2**	**2,413**
Costs incurred	**$ 1,728**	**$ 313**	**$ 655**	**$ 2**	**$ 2,698**

(1) Excludes additions related to the Company's Oil Sands Mining and Upgrading Segment.

(millions of Canadian dollars)	North America	North Sea	2008 Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 299	$ (7)	$ 44	$ –	$ 336
Unproved	84	1	1	–	86
Exploration	144	3	–	1	148
Development	1,810	195	772	–	2,777
Costs incurred	$ 2,337	$ 192	$ 817	$ 1	$ 3,347

(millions of Canadian dollars)	North America	North Sea	2007 Offshore West Africa	Other	Total
Property acquisitions					
Proved	$ 55	$ (38)	$ –	$ –	$ 17
Unproved	13	1	–	–	14
Exploration	239	19	–	1	259
Development	2,173	380	148	–	2,701
Costs incurred	$ 2,480	$ 362	$ 148	$ 1	$ 2,991

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, 2009, 2008, and 2007 are summarized in the following tables:

	2009			
(millions of Canadian dollars)	**North America** [1]	**North Sea**	**Offshore West Africa**	**Total**
Crude oil and natural gas revenue, net of royalties and blending costs	**$ 7,121**	**$ 1,334**	**$ 832**	**$ 9,287**
Production	**(1,748)**	**(376)**	**(179)**	**(2,303)**
Transportation	**(284)**	**(8)**	**(1)**	**(293)**
Depletion, depreciation and amortization [2]	**(2,186)**	**(207)**	**(527)**	**(2,920)**
Asset retirement obligation accretion	**(41)**	**(24)**	**(4)**	**(69)**
Petroleum revenue tax	**–**	**(85)**	**–**	**(85)**
Income tax	**(833)**	**(317)**	**(30)**	**(1,180)**
Results of operations	**$ 2,029**	**$ 317**	**$ 91**	**$ 2,437**

(1) Excludes results of operations from the Company's Oil Sands Mining and Upgrading segment.
(2) Includes the impact of a ceiling test impairment at December 31, 2009 of $993 million, pre-tax.

	2008			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 8,126	$ 1,731	$ 801	$ 10,658
Production	(1,881)	(457)	(102)	(2,440)
Transportation	(327)	(10)	(1)	(338)
Depletion, depreciation and amortization [1]	(9,661)	(1,564)	(132)	(11,357)
Asset retirement obligation accretion	(42)	(27)	(2)	(71)
Petroleum revenue tax	–	(143)	–	(143)
Income tax	1,128	235	(141)	1,222
Results of operations	$ (2,657)	$ (235)	$ 423	$ (2,469)

(1) Includes the impact of a ceiling test impairment at December 31, 2008 of $8,665 million, pre-tax.

	2007			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Crude oil and natural gas revenue, net of royalties and blending costs	$ 7,441	$ 1,522	$ 709	$ 9,672
Production	(1,642)	(432)	(94)	(2,168)
Transportation	(335)	(16)	(1)	(352)
Depletion, depreciation and amortization	(2,359)	(340)	(165)	(2,864)
Asset retirement obligation accretion	(38)	(30)	(2)	(70)
Petroleum revenue tax	–	(141)	–	(141)
Income tax	(997)	(282)	(121)	(1,400)
Results of operations	$ 2,070	$ 281	$ 326	$ 2,677

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 average first-day-of-the-month price during the previous 12-month 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 rather than average first-day-of-the-month prices during the previous 12-month period 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 expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and restoration 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":

	2009			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	**$ 176,866**	**$ 16,304**	**$ 8,305**	**$ 201,475**
Future production costs	**(88,134)**	**(6,929)**	**(3,255)**	**(98,318)**
Future development and asset retirement obligations	**(22,767)**	**(5,271)**	**(975)**	**(29,013)**
Future income taxes	**(11,237)**	**(3,487)**	**(1,229)**	**(15,953)**
Future net cash flows	**54,728**	**617**	**2,846**	**58,191**
10% annual discount for timing of future cash flows	**(35,526)**	**(275)**	**(1,345)**	**(37,146)**
Standardized measure of future net cash flows	**$ 19,202**	**$ 342**	**$ 1,501**	**$ 21,045**

	2008			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 51,913	$ 13,681	$ 6,789	$ 72,383
Future production costs	(23,747)	(6,845)	(3,000)	(33,592)
Future development and asset retirement obligations	(9,238)	(4,674)	(364)	(14,276)
Future income taxes	(3,097)	(2,011)	(1,061)	(6,169)
Future net cash flows	15,831	151	2,364	18,346
10% annual discount for timing of future cash flows	(6,872)	(76)	(1,011)	(7,959)
Standardized measure of future net cash flows	$ 8,959	$ 75	$ 1,353	$ 10,387

(millions of Canadian dollars)		North America		North Sea		Offshore West Africa		Total
				2007				
Future cash inflows	$	71,069	$	30,269	$	9,921	$	111,259
Future production costs		(23,729)		(9,316)		(2,419)		(35,464)
Future development and asset retirement obligations		(7,938)		(4,021)		(621)		(12,580)
Future income taxes		(9,508)		(11,376)		(1,978)		(22,862)
Future net cash flows		29,894		5,556		4,903		40,353
10% annual discount for timing of future cash flows		(13,952)		(2,176)		(2,505)		(18,633)
Standardized measure of future net cash flows	$	15,942	$	3,380	$	2,398	$	21,720

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)		**2009**		2008		2007
Sales of crude oil and natural gas produced, net of production costs	**$**	**(5,437)**	$	(9,679)	$	(7,150)
Net changes in sales prices and production costs		**16,808**		(14,680)		7,412
Extensions, discoveries and improved recovery		**4,222**		820		1,429
Changes in estimated future development costs		**(2,752)**		(715)		(169)
Purchases of proved reserves in place		**53**		113		39
Sales of proved reserves in place		**(7)**		(1)		(103)
Revisions of previous reserve estimates		**220**		112		2,380
Accretion of discount		**1,375**		3,468		2,760
SEC reliable technology		**254**		–		–
SEC rule transition		**7,332**		–		–
Changes in production timing and other		**(2,788)**		767		508
Net change in income taxes		**(8,622)**		8,462		(3,378)
Net change		**10,658**		(11,333)		3,728
Balance – beginning of year		**10,387**		21,720		17,992
Balance – end of year	**$**	**21,045**	$	10,387	$	21,720

TEN-YEAR REVIEW

Years ended December 31	**2009**	2008	2007	2006	2005	2004	2003	2002	2001	2000
FINANCIAL INFORMATION (1) (millions of Canadian dollars, except per share amounts)										
Net earnings	**1,580**	4,985	2,608	2,524	1,050	1,405	1,403	539	639	758
Per share – basic	**$ 2.92**	$ 9.22	$ 4.84	$ 4.70	$ 1.96	$ 2.62	$ 2.62	$ 1.06	$ 1.32	$ 1.62
Cash flow from operations (2)	**6,090**	6,969	6,198	4,932	5,021	3,769	3,160	2,254	1,920	1,884
Per share – basic	**$ 11.24**	$ 12.89	$ 11.49	$ 9.18	$ 9.36	$ 7.03	$ 5.88	$ 4.41	$ 3.96	$ 4.04
Capital expenditures, net of dispositions (including business combinations)	**2,997**	7,451	6,425	12,025	4,932	4,633	2,506	4,069	1,885	2,823
Balance sheet information										
Working capital surplus (deficiency)	**(514)**	(28)	(1,382)	(832)	(1,774)	(652)	(505)	(14)	(6)	(77)
Property, plant and equipment, net	**39,115**	38,966	33,902	30,767	19,694	17,064	13,714	12,934	8,766	7,439
Total assets	**41,024**	42,650	36,114	33,160	21,852	18,372	14,643	13,793	9,290	8,051
Long-term debt	**9,658**	12,596	10,940	11,043	3,321	3,538	2,748	4,200	2,788	2,573
Shareholders' equity	**19,426**	18,374	13,321	10,690	8,237	7,324	6,006	4,754	3,928	3,297
SHARE INFORMATION (1)										
Common shares outstanding (thousands)	**542,327**	540,991	539,729	537,903	536,348	536,361	534,926	535,104	484,804	489,116
Weighted average shares outstanding (thousands)	**541,925**	540,647	539,336	537,339	536,650	536,223	536,940	511,532	485,200	466,804
Dividends declared per common share	**$ 0.42**	$ 0.40	$ 0.34	$ 0.30	$ 0.24	$ 0.20	$ 0.15	$ 0.13	$ 0.10	$ –
Trading statistics (1)										
TSX – C$										
Trading volume (thousands)	**520,160**	679,738	429,034	508,935	637,992	606,024	590,702	619,316	534,976	567,412
Share Price ($/share)										
High	**$ 79.00**	$111.30	$ 80.02	$ 73.91	$ 62.00	$ 27.58	$ 16.81	$ 13.64	$ 13.09	$ 14.05
Low	**$ 35.85**	$ 34.19	$ 52.45	$ 45.49	$ 24.28	$ 15.96	$ 11.30	$ 9.40	$ 8.98	$ 7.45
Close	**$ 76.00**	$ 48.75	$ 72.58	$ 62.15	$ 57.63	$ 25.63	$ 16.34	$ 11.70	$ 9.58	$ 10.38
NYSE – US$										
Trading volume (thousands)	**757,307**	967,228	486,266	401,909	251,554	125,468	46,916	31,864	20,764	3,172
Share Price ($/share)										
High	**$ 76.51**	$109.32	$ 87.17	$ 64.38	$ 54.05	$ 22.37	$ 12.85	$ 8.72	$ 8.63	$ 9.46
Low	**$ 27.69**	$ 26.43	$ 44.56	$ 40.29	$ 19.74	$ 11.94	$ 7.32	$ 5.89	$ 5.70	$ 6.19
Close	**$ 71.95**	$ 39.98	$ 73.14	$ 53.23	$ 49.62	$ 21.39	$ 12.61	$ 7.42	$ 6.10	$ 6.88
RATIOS										
Debt to book capitalization (3)	**33%**	41%	45%	51%	29%	34%	33%	47%	42%	44%
Return on average common shareholders' equity, after tax (3)	**8%**	33%	22%	27%	14%	21%	26%	13%	18%	29%
Daily production before royalties per ten thousand common shares (boe/d)	**10.6**	10.4	11.3	10.8	10.3	9.6	8.5	8.2	7.4	6.6
Total proved and probable reserves per common share (boe) (4)	**11.5**	6.1	6.3	6.4	4.8	4.3	4.0	3.3	3.1	2.9
Net asset value per common share (1)(5)	**$129.83**	$ 79.78	$ 68.93	$ 56.41	$ 60.44	$ 33.13	$ 23.35	$ 19.57	$ 16.88	$ 20.54

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

(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 (constant price and costs, before royalties), using year-end common shares outstanding. Excludes Horizon SCO reserves prior to 2009.

(5) Based upon 10% discounted, forecast price pre-tax proved and probable net present values as reported in the Company's Annual Information Form ("AIF") for reserves, with $250/acre added for core undeveloped land from 2005 to 2009, $75/acre for all years prior, less net debt. Excludes Horizon SCO reserves prior to 2009. Future development costs and associated material well abandonment costs have been applied against future net reserves. Refer to the Year-End Reserves section of the Annual Report.

Years ended December 31	**2009**	2008	2007	2006	2005	2004	2003	2002	2001	2000
OPERATING INFORMATION										
Crude oil and NGLs (mmbbl)										
Company net proved reserves (after royalties)										
North America	**2,664**	948	920	887	694	648	588	571	583	568
North Sea	**240**	256	310	299	290	303	222	202	78	93
Offshore West Africa	**123**	142	128	130	134	115	85	75	60	30
	3,027	1,346	1,358	1,316	1,118	1,066	895	848	721	691
Horizon SCO	–	1,946	1,761	1,596	1,626					
Company net proved and probable reserves (after royalties)										
North America	**4,172**	1,599	1,545	1,502	1,035	926	857	636	670	643
North Sea	**387**	399	405	422	417	415	317	277	100	124
Offshore West Africa	**179**	191	186	195	206	196	133	121	103	37
	4,738	2,189	2,136	2,119	1,658	1,537	1,307	1,034	873	804
Horizon SCO	–	2,944	2,680	2,542	2,566					
Natural gas (bcf)										
Company net proved reserves (after royalties)										
North America	**3,027**	3,523	3,521	3,705	2,741	2,591	2,426	2,446	2,064	1,895
North Sea	**67**	67	81	37	29	27	62	71	94	91
Offshore West Africa	**85**	94	64	56	72	72	64	71	67	53
	3,179	3,684	3,666	3,798	2,842	2,690	2,552	2,588	2,225	2,039
Company net proved and probable reserves (after royalties)										
North America	**3,992**	4,619	4,602	4,857	3,548	3,319	2,919	2,765	2,344	2,214
North Sea	**94**	94	113	93	69	57	102	89	118	114
Offshore West Africa	**124**	131	88	99	110	90	72	90	88	67
	4,210	4,844	4,803	5,049	3,727	3,466	3,093	2,944	2,550	2,395
Total proved reserves (after royalties) (mmboe)	**3,557**	1,960	1,969	1,949	1,592	1,514	1,320	1,279	1,092	1,031
Total proved and probable reserves (after royalties) (mmboe)	**5,440**	2,996	2,937	2,961	2,279	2,115	1,823	1,525	1,298	1,203
Daily production (before royalties)										
Crude oil and NGLs (mbbl/d)										
North America – Conventional	**234**	244	247	235	222	206	175	169	167	155
North America – Oil Sands Mining and Upgrading	**50**	–	–	–	–	–	–	–	–	–
North Sea	**38**	45	56	60	68	65	57	39	36	17
Offshore West Africa	**33**	27	28	37	23	12	10	7	3	2
	355	316	331	332	313	283	242	215	206	174
Natural gas (mmcf/d)										
North America	**1,287**	1,472	1,643	1,468	1,416	1,330	1,245	1,204	906	793
North Sea	**10**	10	13	15	19	50	46	27	12	1
Offshore West Africa	**18**	13	12	9	4	8	8	1	–	–
	1,315	1,495	1,668	1,492	1,439	1,388	1,299	1,232	918	794
Total production (before royalties) (mboe/d)	**575**	565	609	581	553	514	459	421	359	306
Product Pricing										
Average crude oil and NGLs price ($/bbl)	**57.68**	82.41	55.45	53.65	46.86	37.99	32.66	31.22	23.45	31.89
Average natural gas price ($/mcf)	**4.53**	8.39	6.85	6.72	8.57	6.50	6.21	3.77	5.45	4.92

CORPORATE INFORMATION

BOARD OF DIRECTORS

***Catherine M. Best,** FCA, ICD.D (1 - Chair) (2) (5)
Corporate Director,
Calgary, Alberta

N. Murray Edwards (4)
President,
Edco Financial Holdings Ltd.
Calgary, Alberta

***Honourable Gary A. Filmon**, P.C., O.M. (1) (3)
Consultant,
The Exchange Group
Winnipeg, Manitoba

***Ambassador Gordon D. Giffin** (1) (3 - Chair) (4)
Senior Partner,
McKenna Long & Aldridge LLP
Atlanta, Georgia

John G. Langille
Vice-Chairman,
Canadian Natural Resources Limited
Calgary, Alberta

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

Keith A. J. MacPhail (4) (5)
Chairman, President & Chief Executive Officer,
Bonavista Energy Trust
Calgary, Alberta

Allan P. Markin, O.C., A.O.E. (5)
Chairman of the Board,
Canadian Natural Resources Limited
Calgary, Alberta

***Honourable Frank J. McKenna**, P.C., O.C., O.N.B., Q.C. (2) (3)
Deputy Chair,
TD Bank Financial Group
Cap Pelé, New Brunswick

***James S. Palmer**, C.M., A.O.E., Q.C. (2 - Chair) (4) (5)
Chairman & Partner,
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

***Eldon R. Smith**, O.E., M.D. (2) (5 - Chair)
President, Eldon R. Smith + Associates Ltd.
Emeritus Professor and Former Dean,
Faculty of Medicine, University of Calgary
Calgary, Alberta

***David A. Tuer** (1) (3) (4 - Chair)
Vice-Chairman & Chief Executive Officer,
Marble Point Energy Ltd.
Calgary, Alberta

MANAGEMENT COMMITTEE

Allan P. Markin
Chairman of the Board

N. Murray Edwards
Vice-Chairman of the Board

John G. Langille
Vice-Chairman of the Board

Steve W. Laut
President

Tim S. McKay
Chief Operating Officer

Douglas A. Proll
Chief Financial Officer & Senior Vice-President, Finance

Réal M. Cusson
Senior Vice-President, Marketing

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

Peter J. Janson
Senior Vice-President, Horizon Operations

Terry J. Jocksch
Senior Vice-President, International & Thermal

Allen M. Knight
Senior Vice-President, International & Corporate Development

Cameron S. Kramer
Senior Vice-President, North America Operations

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Corey B. Bieber
Vice-President, Finance & Investor Relations

Mary-Jo E. Case
Vice-President, Land

Randall S. Davis
Vice-President, Finance & Accounting

(1) Audit Committee member
(2) Compensation Committee member
(3) Nominating and Corporate Governance Committee member
(4) Reserves Committee member
(5) Health, Safety and Environment 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.

GENERAL INFORMATION

Corporate Governance

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. Canadian Natural, as a "foreign private issuer" in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange ("NYSE") Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

Canadian Natural follows Toronto Stock Exchange ("TSX") rules with respect to shareholder approval of equity compensation 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 and material revisions to such plans. Canadian Natural has a share bonus plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the share bonus plan and under TSX rules the plan is not subject to shareholder approval.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2009 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying the quality of its public disclosure.

CORPORATE OFFICES

Head Office

Canadian Natural Resources Limited
2500, 855 - 2 Street S.W.
Calgary, AB T2P 4J8
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Facsimile: (403) 517-7350
Website: www.cnrl.com

Investor Relations

Telephone: (403) 514-7777
Facsimile: (403) 514-7888
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
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

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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 21.

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 in each of its last three years ended December 31.

	2009	2008	2007
Cash dividends declared per common share	$ 0.42	$ 0.40	$ 0.34

Notice of Annual Meeting

Canadian Natural's Annual and Special Meeting of the Shareholders will be held on Thursday, May 6, 2010 at 3:00 p.m. Mountain Daylight Time in the Ballroom of the Metropolitan Centre, Calgary, Alberta.

Stock Listing – CNQ

The Toronto Stock Exchange
The New York Stock Exchange

Canadian Natural

Canadian Natural Resources Limited
2500, 855 – 2 Street S.W.
Calgary, AB
T2P 4J8

telephone: **403.517.6700**
facsimile: **403.517.7350**
email: **ir@cnrl.com**

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

REPORT OF FOREIGN PRIVATE ISSUER
Pursuant to Section 13a-16 or 15d-16 of the
Securities Exchange Act of 1934

March, 2010

Commission File Number: 333-12138

CANADIAN NATURAL RESOURCES LIMITED
(Exact name of registrant as specified in its charter)

2500, 855 – 2nd Street S.W., Calgary, Alberta, Canada T2P 4J8
(Address of principal executive offices)

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F ___ Form 40-F _X_

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1). ____

Note: Regulation S-T Rule 101(b)(1) only permits the submission in paper of a Form 6-K if submitted solely to provide an attached annual report to security holders.

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): ____

Note: Regulation S-T Rule 101(b)(7) only permits the submission in paper of a Form 6-K if submitted to furnish a report or other document that the registrant foreign private issuer must furnish and make public under the laws of the jurisdiction in which the registrant is incorporated, domiciled or legally organized (the registrant's "home country"), or under the rules of the home country exchange on which the registrant's securities are traded, as long as the report or other document is not a press release, is not required to be and has not been distributed to the registrant's security holders, and, if discussing a material event, has already been the subject of a Form 6-K submission or other Commission filing on EDGAR.

Indicate by check mark whether the registrant by furnishing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934.

Yes ___ No _X_

If "Yes" is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): 82-______

The Annual Report attached hereto as Exhibit 99.1, limited to those portions beginning with the heading "Management's Discussion and Analysis" on page 20 and including "Financial Statements" through to page 87 inclusive, is incorporated by reference into the Registration Statement on Form F-9 (File No. 333-162270) as an exhibit thereto:

Exhibit Number	Description
99.1	Annual Report issued by Canadian Natural Resources Limited to its shareholders referenced as 2009 Annual Report.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CANADIAN NATURAL RESOURCES LIMITED
(Registrant)

Date: March 29, 2010

By: ______________________
Bruce E. McGrath
Corporate Secretary